TITLE: ACCOUNTING FOR AND MODELING OF NETWORK FLOWS INSIDE THE BONNEVILLE POWER ADMINISTRATION'S TRANSMISSION SYSTEM

SHORT TITLE: ACCOUNTING FOR NETWORK FLOWS

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- PRELIMINARY -

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Abstract

Background: The absence of an operational methodology to reliably and accurately account for the sources of energy flow on the Bonneville Power Administration's (BPA) transmission network has limited the ability of the BPA to proactively manage network congestion. Transmission constraints have become a significant operational issue due in part to system load growth, industry deregulation, river-operation constraints, and the increased diversity of generation resources. This paper introduces the preliminary results of an operational model for determining the sources of network flow on constrained network flowgates and to predict future flows several hours in advance. **Methods:** The model makes use of transactional data (i.e. e-Tags), customer load data, federal generation data, inadvertent interchange data, and Power Transfer Distribution Factors (PTDF). Historical data for the period July 1st through August 31st 2007 was analyzed and only data available to the BPA's Transmission Services organization was considered. Ten network flowgates were analyzed and the results are reported here. **Results:** The performance of the model and the ability to use the model as the basis for near-term (hours +1, +2, +3) tools are promising**.** Depending on the techniques used, uncompensated modeling errors during heavy load hours can be as small as 3% to as high as 18% of the OTC *(higher as a percentage of actual flow)*. Forecasting errors of less than 4% of the OTC can be achieved for all flowgates in hours +1, +2, and +3. **Conclusions:** Initial results are promising. Additional research is recommended to explore likely sources of modeling error and to improve and evaluate the performance of the model using time-differentiated forecasted data (bi-temporal). At this time, any conclusions regarding the operational applicability of the model and techniques are premature until further research has been performed.

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1 Introduction

The absence of an operational methodology to reliably and accurately account for the sources of energy flow on the Bonneville Power Administrations (BPA) transmission network has limited the ability of BPA to proactively manage network congestion. Transmission constraints have become a significant operational issue due in part to system load growth, industry deregulation, river-operation constraints, and the increased diversity of generation resources. This paper introduces the preliminary research results of an operational model for determining the sources of network flow on constrained network flowgates and to predict future flows several hours in advance.

Unlike many theoretical or policy based models that focus on weekly, monthly, or yearly perspectives and use contracted uses of the transmission system as their base, the research presented in this paper has an operational perspective with all analysis beginning at real-time. Network models currently in use for the calculation of Available Transfer Capability (ATC) are based on contracted use of the system via contracts or reservations. The model presented in this paper is focused on the operating time horizon (real-time/current day) and utilizes declared uses of the system (transactions/schedules) and actual flow data.

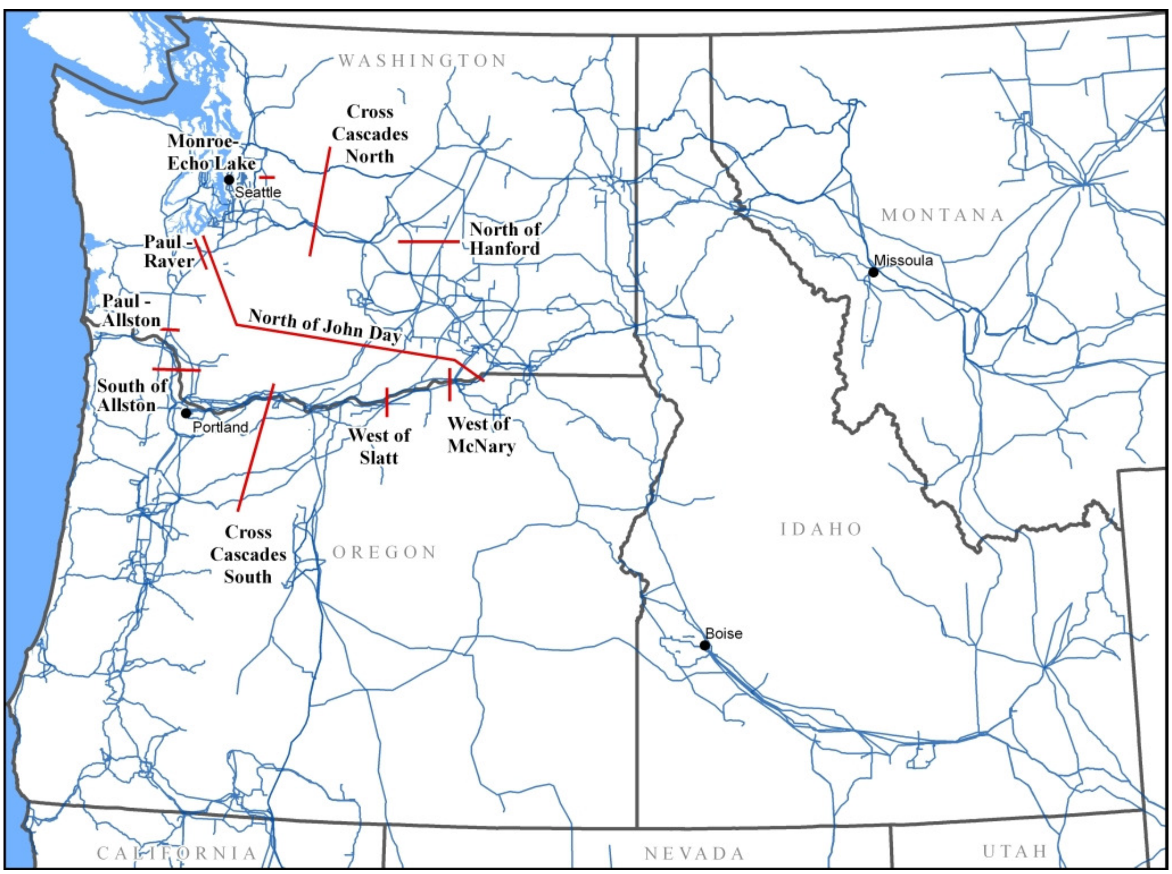


Figure 1 – Network Flowgates

It has historically been considered difficult to calculate or predict network flows within the BPA Transmission System using transactional data. Transaction scheduling has traditionally been done system-to-system or at the net interchange level, such as between the Bonneville Power Administration Power Services organization (BPAP) and PacifiCorp-West (PACW) or between Puget Sound Energy (PSEI) and Avista (AVA). Transactions of this type are of low fidelity and introduce noise when attempting to determine the effects of the transaction on the transmission network. Systems of this type have resources (load and generation) in physically diverse locations of the transmission network. Since transactions with and between these types of systems do not identify the physical location of the energy being injected or withdrawn from the transmission network and instead only identify an aggregate system-to-system transaction, using these types of transactions in a network model can lead to misleading and inaccurate results. Not all system-to-system transactions suffer from the same geographic diversity, but many do and methods must be developed to deal with these types of transactions.

Other than transactional data that has been scheduled and/or tagged, there are numerous other sources of energy flow on the transmission network. Some of the more significant sources include load following customers being served within the BPA Balancing Authority Area, inadvertent interchange and loop flow, dynamic schedules, and un-scheduled transactions that are accounted for after flow has already occurred or using mechanisms other than e-Tags. In addition, any model that is used for forecasting network flow will be highly dependent on estimated data (generation & load estimates, etc.).

As part of a regional Congestion Management initiative, the BPA's Transmission Services organization (BPAT) commissioned this effort to study solutions to these problems and determine if a model could be developed. The preliminary model that was developed as a result of this effort has shown some success in accounting for network flows, predicting future hour flows, and providing insight into potential sources of modeling error.

2 Methods

As an operational (current day) model, this study and the model developed uses transactional data (via e-Tags), customer load actuals, federal generation actuals, inadvertent interchange data, and Power Transfer Distribution Factors (PTDF). Historical data for the period July 1st through August 31st 2007 was analyzed and only data available to the BPA's Transmission Services organization (BPAT) was considered. Ten network flowgates were analyzed and are shown in figure 1 and detailed in the appendix.

2.1 Temporal Data

The data associated with this study exists in two temporal domains (see figure 2): the time "After-Energy-Flow" has occurred (AEF) and the time "Before-Energy-Flow" has occurred (BEF). Only AEF data - sometimes referred to as "actuals" - was considered for this study. Using forecasted or BEF data would have introduced errors in the results that would have obscured the performance of the model and were generally avoided. In addition, the performance of the model was assessed against Actual Flows (AF) on each flowgate.

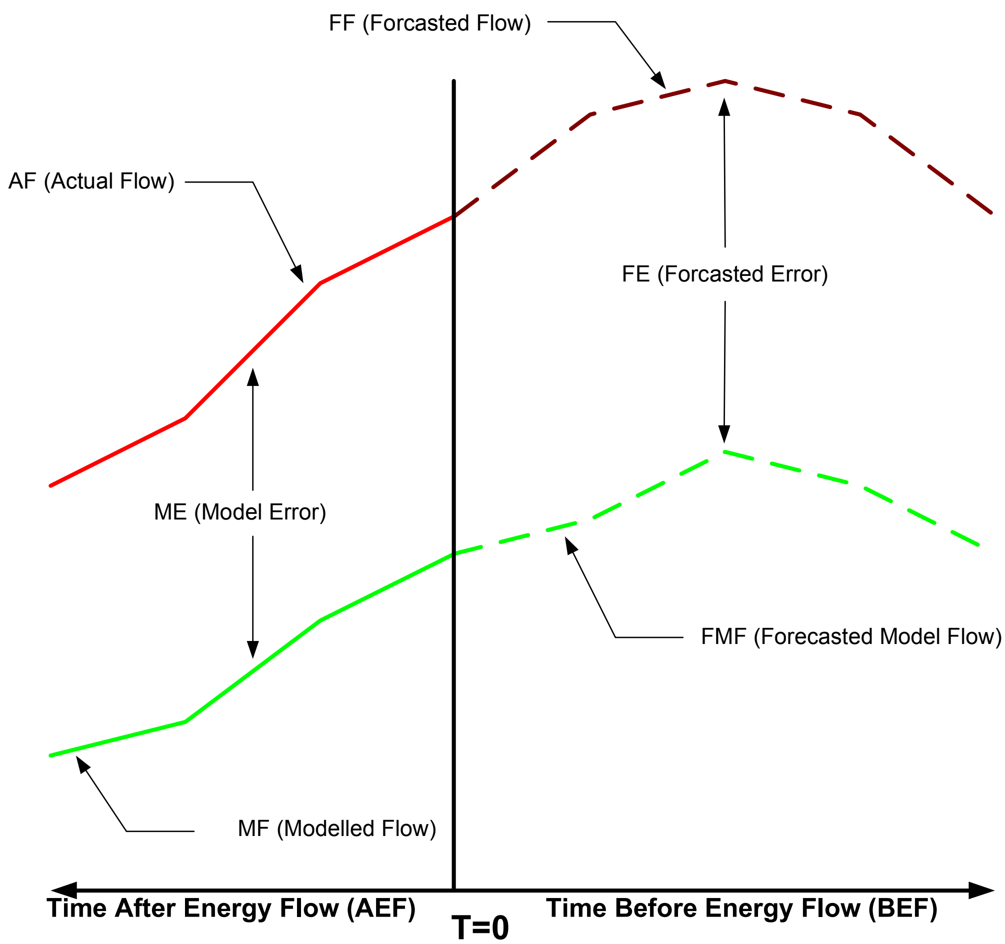


Figure 2 - Definitions

2.2 Modeled Flow

The primary goal of the model is to calculate a Modeled Flow (MF) in the AEF temporal domain that most closely matches the Actual Flow (AF) by minimizing the Model Error (ME) for each flowgate in the study. A secondary goal, and one that depends heavily on the quality of the calculated MF, is the ability to calculate a Forecasted Flow (FF) in the BEF temporal domain. This is accomplished by calculating a Forecasted Model Flow (FMF) using the same techniques used to calculate the MF and then applying feed-forward techniques to generate a FF prediction that minimizes Forecasted Error (FE) - see figure 2. The forecasting details will be described later in this document.

2.2.1 Modeled Flow Basic Function

For any given flowgate, the basic formula used in calculating modeled flow (MF) is as follows:

$$\begin{aligned} MF = &\sum_{n=1}^{x} Tag_n (PTDF_{POR_n} - PTDF_{POD_n}) \\ &+ \sum_{n=1}^{y} Load_n (PTDF_{FCRTS} - PTDF_{Load_n}) \\ &+ \sum_{n=1}^{z} Inadvertent_n (PTDF_{FCRTS} - PTDF_{Inadvertent_n}) \end{aligned}$$

Where:

$Tag_n =$	The energy profile of the n[th] e-Tag that had energy flow
$PTDF_{POR_n} =$	PTDF value for the first BPAT POR on the n[th] e-Tag
$PTDF_{POD_n} =$	PTDF value for the last BPAT POD on the n[th] e-Tag
$Load_n =$	The energy profile of the n[th] non-tagged internal customer loads served by the federal system
$PTDF_{FCRTS} =$	PTDF value for the Federal Columbia River Transmission System (FCRTS) and BPAPower. May be statically or dynamically weighted (see PTDF section)
$PTDF_{Load_n} =$	The PTDF value for the deemed bus representing the Point of Delivery (POD) of the nth customer’s load
$Inadvertent_n =$	The energy profile of the inadvertent flow between BPAT and the n[th] adjacent Balancing Authority

$PTDF_{Inadvertent_n}$ =	The PTDF value for the deemed bus representing the point of interchange with the n^{th} adjacent Balancing Authority

2.3 Forecasted Network Flow

The modeled flow (MF) and actual flow (AF) data sets were analyzed to test the potential ability to generate future-hour forecasted flows (FF). In this analysis, load and generation actual values were used. By using actual values, the uncertainties inherent in the load and generation forecast values are factored out. This allows for a cleaner analysis of forecasting techniques and the impact of modeling errors.

2.3.1 Forecasted Flow Functions

The formula and forecasting technique used are derived from control system theory. The technique considers the values of the modeled flow for the current hour and prior two hours along with the known actual flow from the current hour. These are used to calculate network flows for following hours similar in theory to a feed-forward control system. The formula used for one hour in the future (t=+1) is as follows:

$$FF_{t=+1} = AF_{t=0} + K_a(MF_{t=+1} - MF_{t=0}) - K_b(MF_{t=+1} - 2 * MF_{t=0} + MF_{t=-1})$$

Where:

$t = 0$	The time at which the most recent metered actual flows are available - it is the starting time from which the forecast will be generated.
$AF_{t=0}$	The most recently metered actual flow – the current real-time metered actual.
$MF_{t=0}$	The calculated modeled flow at time t=0
$MF_{t=+1}$	The calculated modeled flow one hour in the future from t=0
$MF_{t=-1}$	The calculated modeled flow one hour in the past from t=0
$FF_{t=+1}$	The forecasted flow one hour in the future
K_a and K_b	Tuning coefficients used to achieve optimal forecasted results.

For hours beyond t=+1, forecasted values are used as the basis for subsequent-hour forecasts. For two hours (t=+2) and three hours (t=+3) into the future, the formulae are as follows:

$$FF_{t=+2} = FF_{t=+1} + K_a(MF_{t=+2} - MF_{t=+1}) - K_b(MF_{t=+2} - 2*MF_{t=+1} + MF_{t=0})$$

And

$$FF_{t=+3} = FF_{t=+2} + K_a(MF_{t=+3} - MF_{t=+2}) - K_b(MF_{t=+3} - 2*MF_{t=+2} + MF_{t=+1})$$

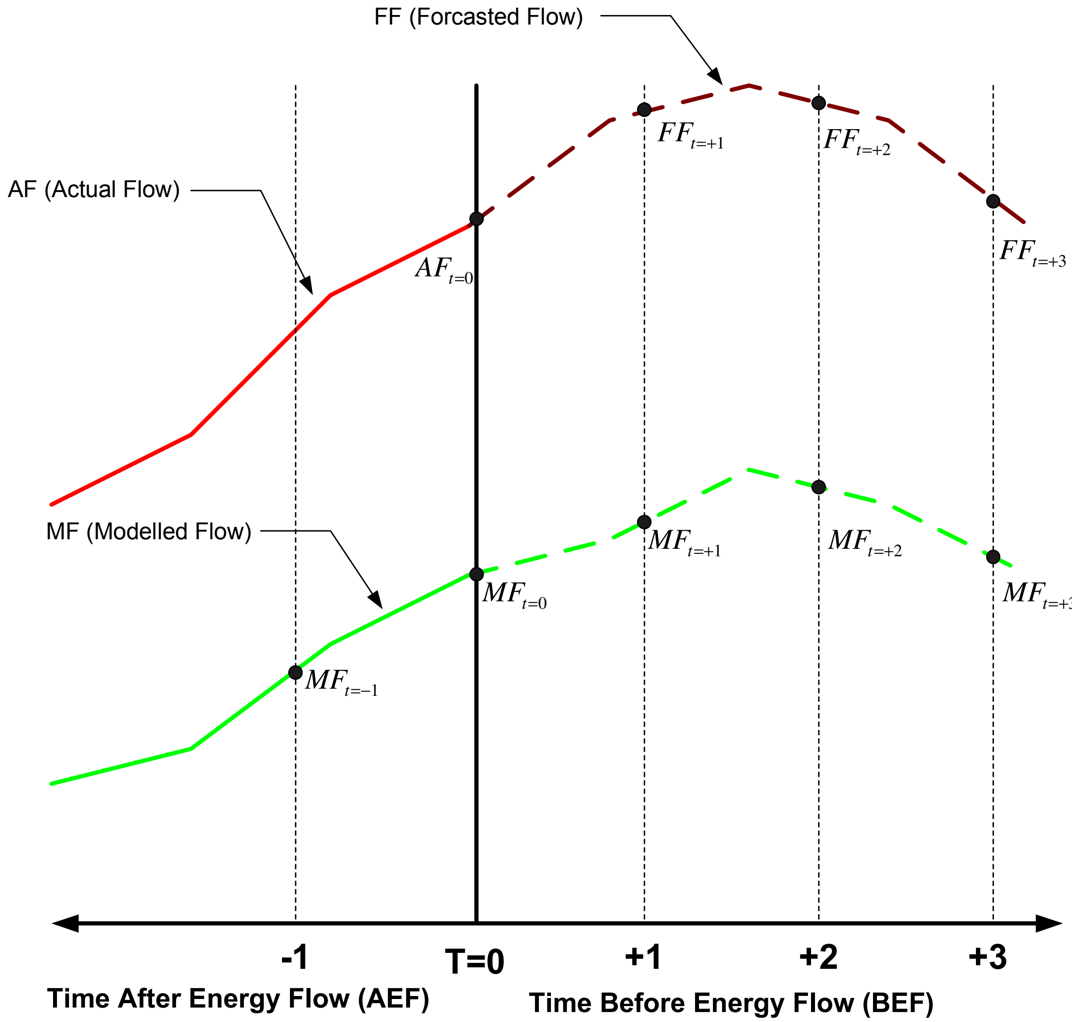


Figure 3 - Forecasted Flow

2.3.2 Tuning Feed-Forward Parameters (K_a and K_b)

$\mathbf{K_a}$ and $\mathbf{K_b}$ are the tuning coefficients used to achieve an optimal feed-forward control loop. By varying $\mathbf{K_a}$ and $\mathbf{K_b}$, the tendency to overshoot or undershoot on forecasted values can be adjusted for optimal results. With $\mathbf{K_a = 1}$ and $\mathbf{K_b = 0}$, the control loop is "detuned" and the forecasted value becomes equal to the **t=+1** modeled flow plus the known error from last hour's forecast.

$$FF_{t=+1} = MF_{t=+1} + (AF_{t=0} - MF_{t=0})$$

This "detuned" feed-forward yields small mean errors but exhibits "ringing" – a tendency to overshoot and undershoot the actual values. Thus, the standard deviation from the actual values is large.

In order to arrive at optimal values for $\mathbf{K_a}$ and $\mathbf{K_b}$, an algorithm examines historical data and calculates which values would have been most successful over a recent historical timeframe and then uses those coefficients for future hour forecasting. The algorithm reevaluates the optimal coefficients on a periodic basis.

For the presented results, after each twelve forecasted hours, the previous 96 hours of data are analyzed. The coefficients that *would have* resulted in the lowest mean absolute error over those 96 hours are then derived. These values for $\mathbf{K_a}$ and $\mathbf{K_b}$ are then used for the next twelve hours of processing. In this way, the control loop responds to the changing nature of the data and produces forecasted results that exhibit a minimum of ringing and a low mean absolute error.

In order to derive the values for $\mathbf{K_a}$ and $\mathbf{K_b}$, each parameter is analyzed in turn. First, $\mathbf{K_b}$ is set to 0, and $\mathbf{K_a}$ is stepped from 1.0 to 0.0 in increments of 0.01. Using a stepped value of $\mathbf{K_a}$, the total absolute error of all forecasts over the historical window is calculated. Then $\mathbf{K_a}$ is adjusted and a new total error is calculated. The error value will decrease until the optimal value of $\mathbf{K_a}$ is reached and then begin increasing. When the optimal value of $\mathbf{K_a}$ is found, the algorithm tunes $\mathbf{K_b}$.

To find $\mathbf{K_b}$, $\mathbf{K_a}$ is set to its optimal value found above and $\mathbf{K_b}$ is varied from 0.0 to 1.0 in 0.01 increments. The total absolute error is calculated over the historical window and the error will decrease until the optimal $\mathbf{K_b}$ is achieved and then begin increasing.

Thus, using these values of $\mathbf{K_a}$ and $\mathbf{K_b}$ would have resulted in the best overall performance of the forecasting function and are therefore used until the next reevaluation occurs.

It has been found that using longer historical windows improves results with diminishing returns after 96 hours. Reevaluation at a frequency of greater than every 12 hours marginally improves results at the expense of computation time.

2.3.3 Alternate Methods of Forecasting Flow

It is also possible to forecast flow based on a simple formula that accounts for the average historical forecasting error.

$$FF_{t=+1} = MF_{t=+1} + \frac{\sum_{n=0}^{m}(AF_{t=-n} - MF_{t=-n})}{m+1}$$

For many flowgates this method yields results that are competitive with the tuned feed-forward approach used above in the t=+4 and beyond time frame. However, for t=+1, t=+2, and t=+3 forecasting, the tuned feedback approach is generally superior.

2.4 Power Transfer Distribution Factors (PTDF)

Power Transfer Distribution Factors (PTDF), sometimes referred to as Path Use Factors (PUF), are used to allocate MW loading on each flowgate in proportion to the MWs being transmitted by each transaction. Bus level PTDF data was produced for each flowgate in the study using the PowerWorld power flow application from a modified 2007 WECC base case using Grand Coulee as the reference (slack) bus.

As appropriate, system level Points of Receipt (POR) and system level Points of Delivery (POD), such as those used by e-Tags and schedules, were deemed to a specific bus. Deeming a bus for system level point introduces errors into the model. Using Injection Groups or multiple prorated bus level PTDF data would be preferable. However, this simple approach was chosen as the basis for this study as to more closely mimic the approach currently being utilized in the Short Term Market (STM) by BPAT.

In the case of the Federal Columbia River Transmission System (FCRTS) and the Bonneville Power Administration's Power Service organization (BPAP), two approaches were used to develop a more sophisticated system level PTDF value that would more accurately account and correct for the large geographic diversity of federal load and generation on the FCRTS. In one approach, a presumed dispatch of federal generation resources was assumed and a statically weighted federal PTDF value produced. A second approach produces a dynamically weighted PTDF value by utilizing hourly federal generation actuals. Most of this study used the dynamically weighted PTDF values as detailed in the results section of this document.

2.5 Operating Transfer Capability and Actual Flows

For each of the ten flowgates that were studied, the Operating Transfer Capability (OTC) and Actual Flow (AF) data were retrieved from historically archived SCADA data for the period July 1st through August 31st. The OTC and AF data was used to assess the performance of the model but was also the basis for next hour forecasting.

The accuracy of the SCADA transducers have a nameplate error of between 0.2% and 0.5%, however a 1% error of SCADA analog readings is generally assumed.S

2.6 Tags

E-Tags represent the primary source of transactional data in the model. E-Tags are required for all transactions that cross Balancing Authority Area boundaries as well as for dynamic schedules and most loss returns. For many other types of transactions they are optional. All implemented e-Tags for the period July 1st through August 31st were analyzed. PTDF values were selected for each e-Tag based on the first BPAT POR and last BPAT POD. In the rare case where a first POR or last POD was not easily identifiable, the upstream Control Area (UPCA) and downstream Control Area (DNCA) were instead used. Based on the PTDF values selected for the tag, each flowgate was allocated a portion of the e-Tag's energy profile as appropriate.

2.7 Federal Generation

In order to calculate dynamically weighted PTDF data for the FCRTS and BPAP (see PTDF section), generation actuals from fifteen different federal projects were used. Hourly generation actuals were retrieved from historically archived Automatic Generation Control (AGC) data for the period July 1st through August 31st. The plants used include the following:

Albeni Falls
Bonneville
Chief Joseph
Dworshak
Grand Coulee
Hungry Horse
Ice Harbor
John Day
Libby
Little Goose
Lower Granite
Lower Monumental
McNary
The Dalles
Columbia Gen Station

2.8 Load Data

Load actuals for over 60 BPAP load following customers located within the BPAT system were provided by BPA's Agency Load Forecasting organization. In order to integrate the load data into the model, PTDF data for each customer was needed. Each of the 60 customers systems were deemed to a bus and the corresponding PTDF value used. Each of these customer's loads is served from the federal system by BPAP. As such, proxy transactions were created from BPAP to each customer and integrated into the model.

Several load following customers, such as Cowlitz, Emerald, and McMinnville are tagged. As a result, tags from BPAP to each of them were filtered out of the model to avoid accounting for their load twice.

2.9 Inadvertent/Unscheduled Interchange

A source of energy flow in the Bonneville Transmission Network is Balancing Authority Area inadvertent interchange (a.k.a. unscheduled interchange) and the corresponding loop flow (see unscheduled interchange in the appendix). Accounting for this unintentional flow was accomplished by retrieving, for the period of the study, both the scheduled and actual interchange values for every adjacent Balancing Authority Area and then calculating the associated inadvertent interchange. Each adjacent Balancing Authority Area (16) was subsequently deemed to a bus and a proxy transaction created from BPAP to each adjacent Balancing Authority Area and integrated into the model. The adjacent Balancing Authority Areas include:

Avista
BCTC
California ISO
Chelan County PUD
Douglas County PUD
Grant County PUD
Idaho Power Company
LA Dept. of Water and Power
NorthWestern Energy
Pacificorp West
Portland General Electric Co.
Puget Sound Energy
Sacramento Municipal Utility District
Seattle City Light
Sierra Pacific
Tacoma Public Utilities

By modeling the inadvertent this way any actual Balancing Authority Area net inadvertent will be associated with federal generation resources (BPAP).

2.10 Outages

Outages, planned or otherwise, are recognized to effect PTDF values and consequently the calculated results of the model. Depending on the type and location of the outage the effect could be significant. For the purposes of this study, outages were not directly incorporated into the model. The effect of outages will be addressed further in the discussion and conclusions section of this document.

2.11 Technology

The majority of the model and forecasting implementation was written in the Java programming language. One exception is an application written in C# (.Net) for calculating PTDF data from a PowerWorld base case. In most circumstances the results of the model were exported to Excel spreadsheets for analysis.

3 Results

A variety of datasets were analyzed to asses the impact of the data on the results and the overall performance of the model. The following datasets were used:

Dataset #1: Electronic Tags (both normal and dynamic) and Dynamic PTDF's for the federal system (e.g. FCRTS or BPAPower). This dataset was used to assess the impact of ONLY using tags.

Dataset #2: In addition to the data used in dataset #1, load following customer data was added to the model.

Dataset #3: In addition to the data used in dataset #2, inadvertent interchange was added to the model and represents the most complete set of operational data available.

Dataset #4: This dataset was created to assess the impact of using static PTDFs instead of dynamic PTDFs. This is the only difference between it and dataset #3.

Dataset #5: As dynamic tagging has become more common, this dataset was created to assess the impact of excluding dynamic tags. This is the only difference between it and dataset #3.

The datasets are summarized in the table below:

Dataset	e-Tags	Dynamic e-Tags	Dynamic PTDFs	Customer Loads	Inadvertent Interchange	Static PTDFs
#1	✓	✓	✓			
#2	✓	✓	✓	✓		
#3	✓	✓	✓	✓	✓	
#4	✓	✓		✓	✓	✓
#5	✓		✓	✓	✓	

The following statistics were calculated to assess the performance of various datasets and models:

Correlation Factor: A number between -1.0 and 1.0 that indicates the general "fit" of two sets of data. For our purposes, we are comparing the Actual Flow (AF) with the Modeled Flow (MF). A value of 1.0 is ideal. [CORREL(AF,MF)]

Mean Error: The mean of the difference between the Actual Flow (AF) and the Modeled Flow (MF) – essentially the mean of the observed Model Error (ME). [AVERAGE(ME)]

Standard Deviation of Error: The standard deviation of the difference between the Actual Flow (AF) and the Modeled Flow (MF). [STDEV(ME)]

Mean of Abs. Error The mean of the absolute difference between the Actual Flow (AF) and the Modeled Flow (MF). [AVERAGE (|ME|)]

Standard Deviation of Abs. Error: The standard deviation of the absolute difference between the Actual Flow (AF) and the Modeled Flow (MF). [STDEV(|ME|)]

% Relative Error (Actual): The error, as a percent, of the mean absolute error relative to the mean absolute Actual Flow. [AVERAGE(|ME|)/AVERAGE(|AF|)]

% Relative Error (OTC): The error, as a percent, of the mean absolute error relative to the mean absolute Operating Transfer Capability (OTC). [AVERAGE(|ME|)/AVERAGE(|OTC|)]

Mean of Actual Flow: The mean of the Actual Flow (AF). [AVERAGE(AF)]

Mean of OTC: The mean of the Operating Transfer Capability (OTC). [AVERAGE(OTC)]

3.1 Modeled Network Flows

For each dataset, statistics were produced for the period July 1st through August 31st for all hours and heavy load hours (HE07-HE22)

A summary of the statistical results is presented below for dataset #3 during heavy load hours for the period July 1st through August 31st. Detailed statistics and charts of the results are available in the appendix.

3.1.1 Modeled Flow Summary Statistics – Dataset #3

Modeled Network Flow Results									
July 1 - August 31 Heavy Load Hours **Model Dataset #3 Tags / Loads / Inadv / Dynamic PTDFs**	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)	MEAN ACTUAL	MEAN OTC
Cross Cascades North	0.946	271.1	214.2	302.9	166.3	8.18%	2.91%	3702.6	10411.6
Cross Cascades South	0.787	63.7	253.9	212.6	152.6	7.13%	2.83%	2982.8	7511.3
Monroe-Echo Lake	0.951	-267.8	100.1	268.0	99.6	30.68%	16.96%	866.7	1580.4
North of Hanford	0.987	81.3	171.0	155.5	107.9	6.55%	3.54%	2351.2	4396.7
North of John Day	0.985	411.9	215.3	416.9	205.4	8.72%	5.51%	4780.8	7571.7
Paul-Allston	0.976	-100.1	68.0	105.1	60.0	6.47%	3.49%	1624.3	3011.5
Raver-Paul	0.974	290.1	52.4	290.1	52.4	48.30%	18.36%	597.8	1580.4
South of Allston	0.941	112.0	163.2	164.4	110.0	9.24%	6.11%	1779.4	2691.2
West of McNary	0.771	26.6	137.7	110.8	85.9	7.08%	3.94%	1563.9	2808.2
West of Slatt	0.947	297.0	132.0	298.0	129.6	11.21%	7.27%	2657.7	4099.9

3.2 Forecasted Network Flow

Forecasted Flows for hours +1, +2, and +3 were produced using dataset #3 (see modeled flow results) and table below.

Dataset	e-Tags	Dynamic e-Tags	Dynamic PTDFs	Customer Loads	Inadvertent Interchange	Static PTDFs
#3	✓	✓	✓	✓	✓	

For each forecasted hour (+1, +2, +3) the same statistics were produced as those used for the modeled flow results. Unlike the model flow results, the statistics represent *all hours of the day* for the period July 1st through August 31st.

A summary of the T=+2 statistical results is presented below for dataset #3 for all hours during the period July 1st through August 31st. Detailed statistics and charts of the forecasting results are available in the appendix.

3.2.1 Forecasted Flow Summary Statistics – Dataset #3, T=+2

Forecasted Network Flow Results (T=+2)									
July 1 - August 31 All Hours (T=+2) Model Dataset #3 Tags / Loads / Inadv / Dynamic PTDFs	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)	MEAN ACTUAL	MEAN OTC
Cross Cascades North	0.976	2.4	181.5	127.3	129.3	3.79%	1.20%	3362.0	10624.4
Cross Cascades South	0.882	2.0	168.1	122.0	115.6	4.27%	1.61%	2855.5	7583.6
Monroe-Echo Lake	0.991	0.6	58.7	41.8	41.1	5.47%	2.64%	715.0	1582.2
North of Hanford	0.992	0.6	168.8	124.7	113.8	6.71%	2.85%	1700.3	4380.2
North of John Day	0.992	1.7	204.7	153.8	135.0	3.81%	2.02%	4036.1	7611.4
Paul-Allston	0.990	0.2	59.1	44.1	39.3	3.12%	1.51%	1414.4	2912.2
Raver-Paul	0.985	0.1	52.0	39.2	34.1	7.68%	2.48%	484.4	1582.2
South of Allston	0.983	0.6	112.4	85.0	73.5	5.77%	3.17%	1472.0	2681.1
West of McNary	0.958	0.4	79.0	52.5	59.0	3.66%	1.87%	1436.5	2805.8
West of Slatt	0.980	0.9	107.2	71.3	80.0	2.96%	1.74%	2408.6	4099.9

4 Discussion & Conclusion

Of the datasets analyzed, the effect of including network load actuals and inadvertent flow data generally improved the performance of the model. While some paths did show slightly worse results, the general effect of adding this data to the model is beneficial. In addition, the effect of using static PTDF values also produced worse results.

The periods of time where the accuracy of the model is most critical are when a flowgate is experiencing heavy flows and nearing the OTC limit. While statistics were produced for heavy load hours, statistics were not compiled for periods of peak flow. A larger dataset that covers multiple seasons and operating conditions would be necessary.

Outages were not directly included in this analysis. The PTDF values used were based off a single base case and were not adjusted to take into account any planned or unplanned outages. It is believed that the performance of the model would improve if they were considered. An effort is under way to determine how accurate the underlying power system model is and the effect of outages on the results. In this effort no transactional data will be used. Instead only actual generation, interchange, and load data will be analyzed. The results should provide a baseline for comparing the results presented in this document and future enhancements.

The base case used to produce PTDF values was a cut case. Only the Northwest system was considered and the remainder of the WECC system was equivalenced. In addition to considering outages and their effect on the model's results, using a full WECC base case is being considered and will be done as time permits.

As detailed in the results section of this document, the near-term forecasting results are also promising. A simple feed-forward technique produces good results for up to three hours into the future. At approximately the fourth hour, using the average error produces as good or better results. As the quality of the modeled flow results improve so will the ability to forecast network flows further into the future. It should also be noted that the forecasting results did not use forecasted time-differentiated (bi-temporal) data. As such, the actual results using forecasted data, as apposed to actuals, is expected to be worse than the statistics presented and additional research is necessary.

Some areas of the system, such as the mid-Columbia area (a.k.a. MIDC, MIDCRemote) also present modeling challenges as do system-to-system scheduling practices, untagged/unscheduled energy flows, and PTDF deeming errors. As modeling techniques, additional research, and possible operational procedures are developed to deal with these complexities, the performance of the model and the ability to forecast network flows will improve.

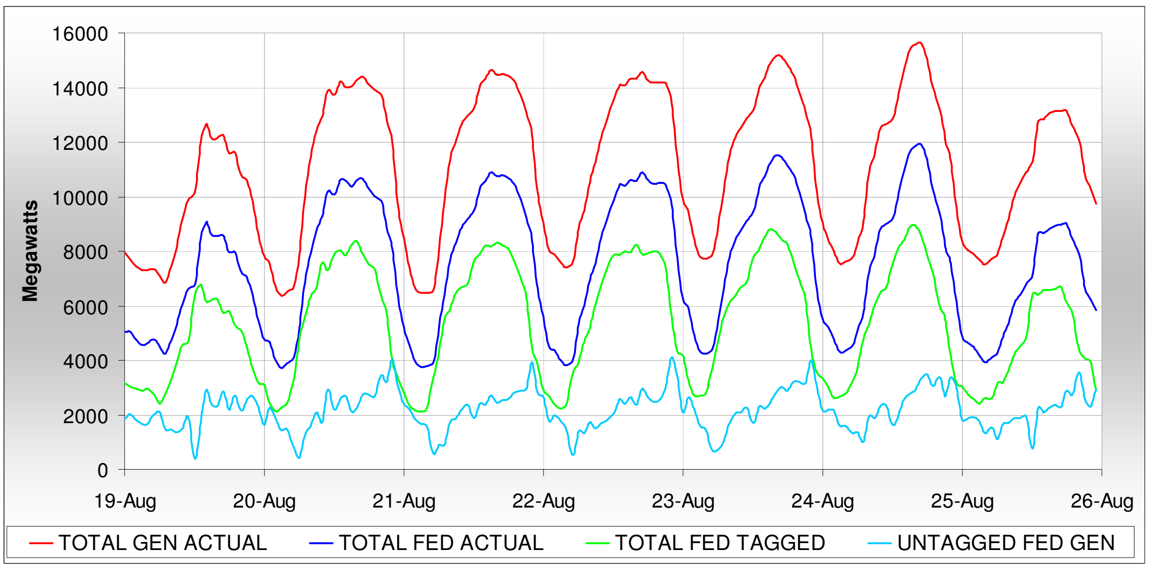
Finally, it should be noted that the preliminary results presented in this document have not been independently verified. While the research team believes the results to be correct, there may exist unintentional modeling, statistical, or analytical errors.

Note: *A special section has been included in the appendix of this document that details an enhanced model that makes extensive use of interchange actuals to improve the calculated results.*

5 Appendix

5.1 Untagged Federal Generation

For the week of August 19th the graph below shows the total amount of generation in the BPA Balancing Authority Area (**red**) compared with the total Federal generation (**blue**) versus total federal generation that is tagged (**green**). The difference between the total federal generation and the total tagged federal generation (**light blue**) must be modeled using techniques other than tags such as customer load actuals and forecasts.



5.2 Unscheduled Interchange

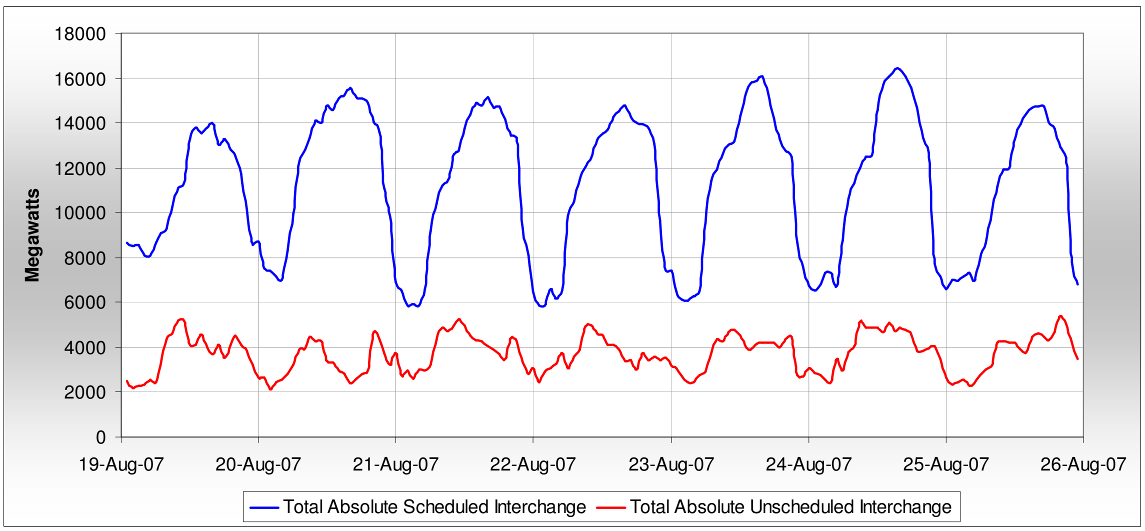
For the week of August 19^{th} the graph below shows the total absolute amount of scheduled (**blue**) and unscheduled (**red**) interchange between the BPA Balancing Authority Area and all adjacent Balancing Authority Areas (Average 3700MW Unscheduled). The formulas are as follows:

Total Absolute Scheduled Interchange (**blue**) =

$$\sum_{n=1}^{16} \left| ScheduledInterchange_n \right|$$

Total Absolute Unscheduled Interchange (**red**) =

$$\sum_{n=1}^{16} \left| ActualInterchange_n - ScheduledInterchange_n \right|$$



The adjacent Balancing Authority Areas in the graph above include the following:

Avista
BCTC
California ISO
Chelan County PUD
Douglas County PUD
Grant County PUD
Idaho Power Company
LA Dept. of Water and Power
NorthWestern Energy
Pacificorp West
Portland General Electric Co.
Puget Sound Energy
Sacramento Municipal Utility District
Seattle City Light
Sierra Pacific
Tacoma Public Utilities

5.3 Network Flowgate Descriptions

a. **Monroe-Echo Lake** Flowgate consists of the Monroe-Echo Lake 500kV Line (north-to-south).

b. **Raver-Paul** Flowgate consists of the Raver-Paul 500 kV Line (north-to-south)

c. **Paul-Allston** Flowgate consists of the following transmission lines (north-to-south):

- Napavine-Allston #1 500kV;and
- Paul-Allston #2 500kV.

d. **South of Allston** Flowgate consists of the following transmission lines (north-to-south):

- Keeler-Allston 500kV;
- Trojan-St. Marys 230kV;
- Trojan-Rivergate 230kV;
- Ross-Lexington 230kV;
- St. Helens-Allston 115KV;
- Merwin-St. Johns 115KV;
- Seaside-Astoria 115KV; and
- Clatsop 230/115KV

e. **North of Hanford** Flowgate consists of the following transmission lines (north-to-south):

- Vantage-Hanford 500kV;
- Grand Coulee-Hanford 500kV; and
- Shultz-Wautoma 500kV (effective upon energization in 2006)

f. **North of John Day** Flowgate consists of the following transmission lines (north-to-south):

- Ashe-Marion 500kV;
- Ashe-Slatt 500kV;
- Wautoma-Ostrander 500kV;
- Wautoma-John Day 500kV;
- Raver-Paul 500kV; and
- Lower Monumental-McNary 500kV.

g. **West of McNary** Flowgate consists of the following transmission lines (east-to-west):

- Coyote Springs-Slatt 500kV;
- McNary-Ross 345kV;
- McNary-Horse Heaven 230kV; and
- McNary-Santiam 230kV.

h. **Cross Cascades North** Flowgate consists of the following transmission lines (east-to-west):

- Schultz-Raver #1, 3, & 4 500kV;
- Schultz-Echo Lake #1 500kV;
- Chief Joseph-Monroe 500kV;
- Chief Joseph-Snohomish #1 & 2 345kV;
- Rocky Reach-Maple Valley 345kV;
- Grand Coulee-Olympia 287kV; and
- Columbia-Covington 230kV.

i. **Cross Cascades South** Flowgate consists of the following transmission lines (east-to-west):

- Big-Eddy-Ostrander 500kV;
- Ashe-Marion 500kV;
- Buckley-Marion 500kV;
- Hanford-Ostrander 500kV;
- John Day-Marion 500kV;
- McNary-Ross 345kV;
- Big Eddy-Chemawa 230kV;
- Big Eddy-McLaughlin 230kV;
- Midway-North Bonneville 230kV;
- McNary-Santiam 230kV; and
- Parkdale-Troutdale 230kV.

j. **West of Slatt** Flowgate consists of the following transmission lines (east-to-west):

- Slatt-Buckley 500kV; and
- Slatt-John Day 500kV

5.4 Modeled Flow Results Statistics

5.4.1 Cross Cascades North (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.900	1603.1	264.4	1603.1	264.4	43.30%	15.40%
#2 - Tags / Loads / Dynamic PTDFs	0.919	915.5	238.5	915.5	238.5	24.73%	8.79%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.946	271.1	214.2	302.9	166.3	8.18%	2.91%
#4 - Tags / Loads / Inadv / Static PTDFs	0.908	444.8	264.1	464.8	227.2	12.55%	4.46%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.870	2483.8	300.4	2483.8	300.4	67.08%	23.86%
MEAN ACTUAL							3702.6
MEAN OTC							10411.6

5.4.2 Cross Cascades South (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.725	965.7	232.9	965.7	232.9	32.38%	12.86%
#2 - Tags / Loads / Dynamic PTDFs	0.751	289.8	230.7	313.9	196.7	10.52%	4.18%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.787	63.7	253.9	212.6	152.6	7.13%	2.83%
#4 - Tags / Loads / Inadv / Static PTDFs	0.777	89.8	276.2	239.8	163.7	8.04%	3.19%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.599	1766.6	269.2	1766.6	269.2	59.23%	23.52%
MEAN ACTUAL							2982.8
MEAN OTC							7511.3

5.4.3 Monroe-Echo Lake (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.950	-147.7	100.8	154.4	90.3	17.68%	9.77%
#2 - Tags / Loads / Dynamic PTDFs	0.952	-230.4	101.0	231.1	99.3	26.46%	14.62%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.951	-267.8	100.1	268.0	99.6	30.68%	16.96%
#4 - Tags / Loads / Inadv / Static PTDFs	0.944	-208.8	102.3	209.7	100.5	24.01%	13.27%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.945	-1.1	103.6	82.9	62.1	9.49%	5.24%
MEAN ACTUAL							866.7
MEAN OTC							1580.4

5.4.4 North of Hanford (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.984	446.1	224.0	461.0	191.4	19.42%	10.48%
#2 - Tags / Loads / Dynamic PTDFs	0.989	290.9	151.0	300.1	131.6	12.64%	6.83%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.987	81.3	171.0	155.5	107.9	6.55%	3.54%
#4 - Tags / Loads / Inadv / Static PTDFs	0.899	661.2	511.3	737.2	393.7	31.06%	16.77%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.979	554.2	261.1	567.4	231.0	23.90%	12.91%
MEAN ACTUAL							2351.2
MEAN OTC							4396.7

5.4.5 North of John Day (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.987	1482.2	204.2	1482.2	204.2	31.00%	19.57%
#2 - Tags / Loads / Dynamic PTDFs	0.989	651.4	177.2	651.7	176.3	13.63%	8.61%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.985	411.9	215.3	416.9	205.4	8.72%	5.51%
#4 - Tags / Loads / Inadv / Static PTDFs	0.950	600.6	386.6	616.1	361.5	12.89%	8.14%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.978	1864.8	260.5	1864.8	260.5	39.00%	24.63%
MEAN ACTUAL							4780.8
MEAN OTC							7571.7

5.4.6 Paul-Allston (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.979	103.8	61.4	106.1	57.4	6.53%	3.52%
#2 - Tags / Loads / Dynamic PTDFs	0.981	-105.6	65.8	110.0	58.2	6.77%	3.65%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.976	-100.1	68.0	105.1	60.0	6.47%	3.49%
#4 - Tags / Loads / Inadv / Static PTDFs	0.940	-11.2	103.9	84.4	61.6	5.19%	2.80%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.970	191.2	75.0	191.3	74.9	11.78%	6.35%
MEAN ACTUAL							1624.3
MEAN OTC							3011.5

5.4.7 Raver-Paul (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.964	655.6	61.6	655.6	61.6	109.15%	41.49%
#2 - Tags / Loads / Dynamic PTDFs	0.977	294.7	49.9	294.7	49.9	49.07%	18.65%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.974	290.1	52.4	290.1	52.4	48.30%	18.36%
#4 - Tags / Loads / Inadv / Static PTDFs	0.916	390.8	94.1	390.8	94.1	65.06%	24.73%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.953	732.7	70.5	732.7	70.5	121.97%	46.36%
MEAN ACTUAL							597.8
MEAN OTC							1580.4

5.4.8 South of Allston (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.944	-265.9	159.0	270.4	151.2	15.20%	10.05%
#2 - Tags / Loads / Dynamic PTDFs	0.945	88.0	157.5	147.0	104.6	8.26%	5.46%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.941	112.0	163.2	164.4	110.0	9.24%	6.11%
#4 - Tags / Loads / Inadv / Static PTDFs	0.911	244.6	204.6	277.8	156.5	15.61%	10.32%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.920	-5.5	199.0	161.5	116.4	9.07%	6.00%
MEAN ACTUAL							1779.4
MEAN OTC							2691.2

5.4.9 West of McNary (statistics)

July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.743	280.5	147.9	283.0	143.0	18.10%	10.08%
#2 - Tags / Loads / Dynamic PTDFs	0.748	178.0	145.0	189.9	129.1	12.14%	6.76%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.771	26.6	137.7	110.8	85.9	7.08%	3.94%
#4 - Tags / Loads / Inadv / Static PTDFs	0.722	-90.0	169.1	154.7	112.9	9.89%	5.51%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.721	562.4	149.2	562.4	149.2	35.96%	20.03%
MEAN ACTUAL							1563.9
MEAN OTC							2808.2

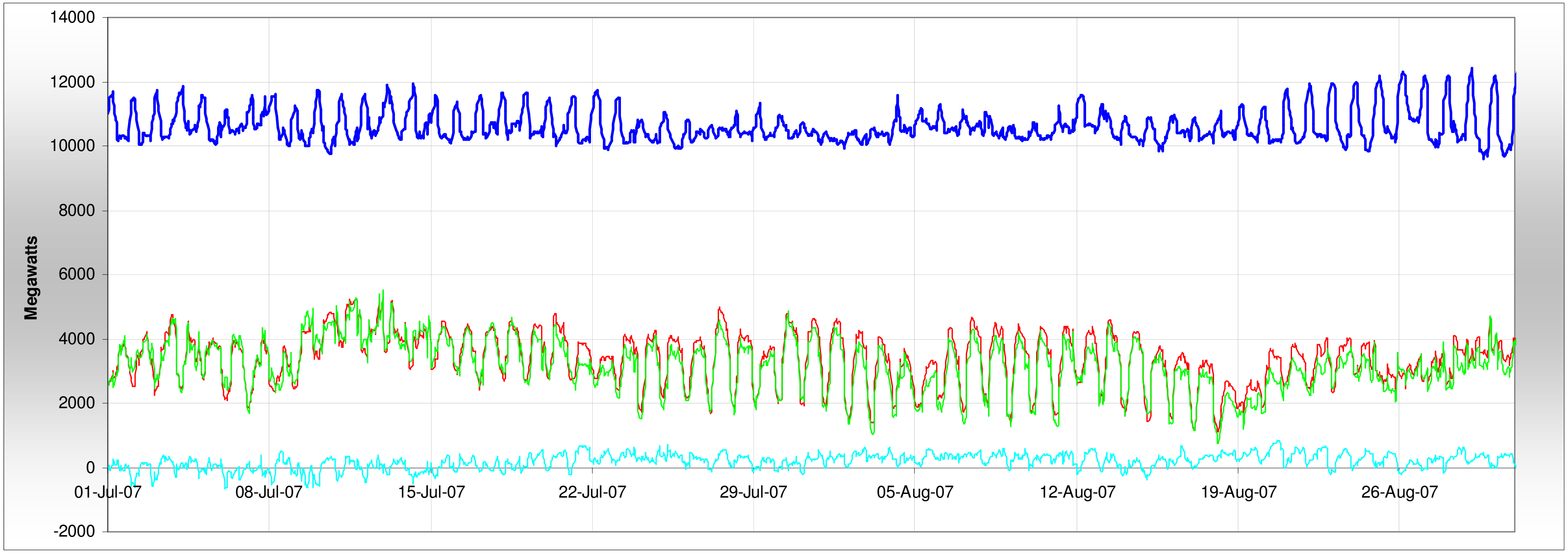
5.4.10 West of Slatt (statistics)

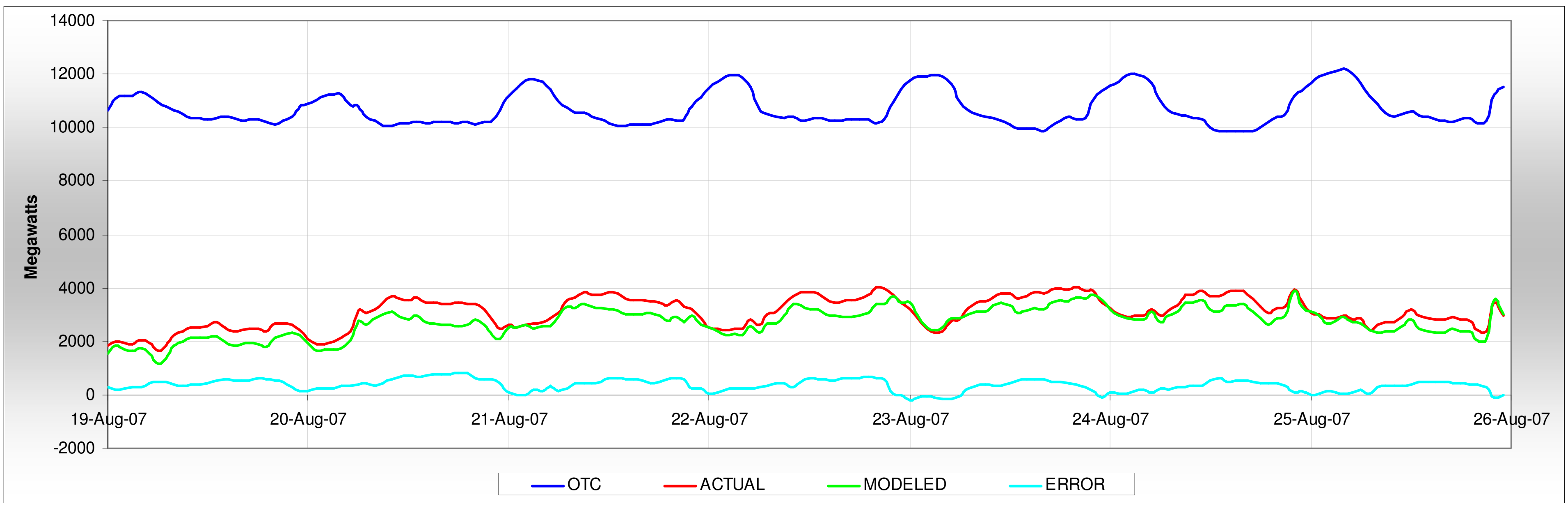
July 1 - August 31 Heavy Load Hours Model Dataset	CORRELATION	MEAN ERROR	STDEV of ERROR	MEAN ABS ERROR	STDEV of ABS ERROR	% RELATIVE ERROR (ACTUAL)	% RELATIVE ERROR (OTC)
#1 - Tags / Dynamic PTDFs	0.955	623.9	123.1	623.9	123.1	23.48%	15.22%
#2 - Tags / Loads / Dynamic PTDFs	0.960	467.5	116.7	467.5	116.7	17.59%	11.40%
#3 - Tags / Loads / Inadv / Dynamic PTDFs	0.947	297.0	132.0	298.0	129.6	11.21%	7.27%
#4 - Tags / Loads / Inadv / Static PTDFs	0.912	284.1	173.3	291.7	160.1	10.97%	7.11%
#5 - Tags / No Dynamic Tags / Dynamic PTDFs	0.944	1156.6	133.3	1156.6	133.3	43.52%	28.21%
MEAN ACTUAL							2657.7
MEAN OTC							4099.9

5.5 Modeled Flow Result Charts

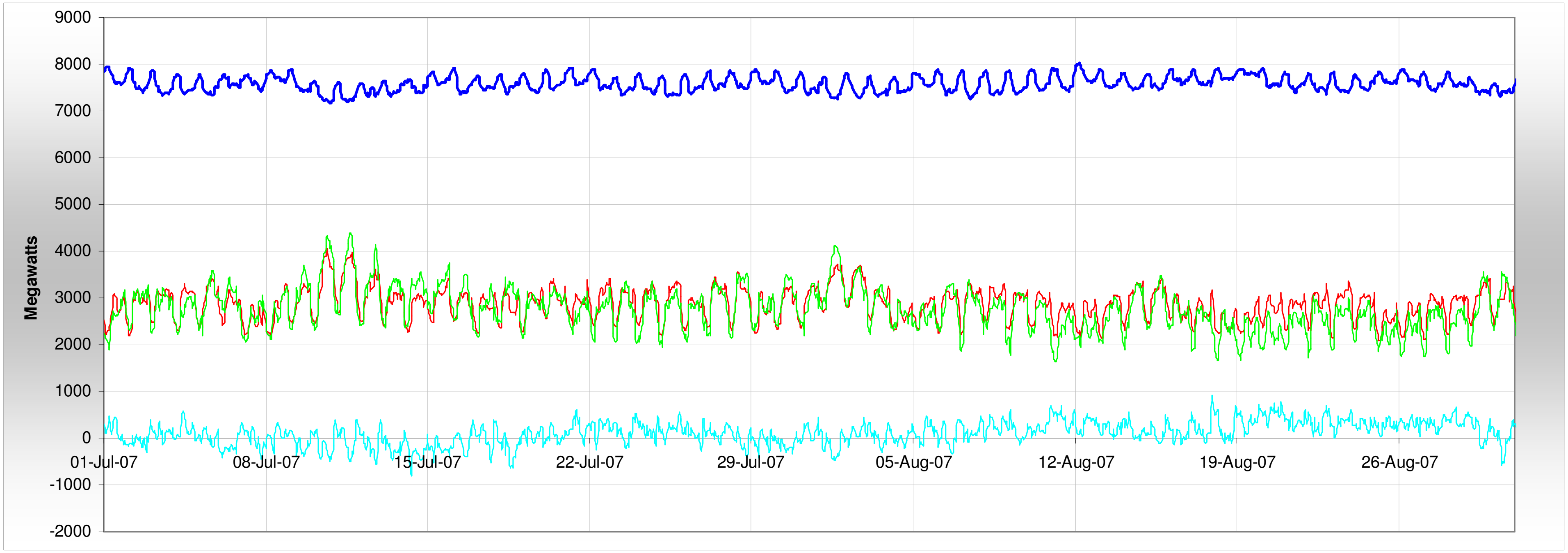
Two charts have been provided for each flowgate that visually summarize the performance of the Model: one for the period July 1st through August 31st and another that details the week of August 19th. They show the Actual Flow (AF) versus the Modeled Flow (MF) where the model is based on Dynamic BPAP PTDFs, e-Tags with Dynamic Tags, Load Actuals by deemed customer bus, and Inadvertent Flow (**Dataset #3** – see Modeled Flow Results sections).

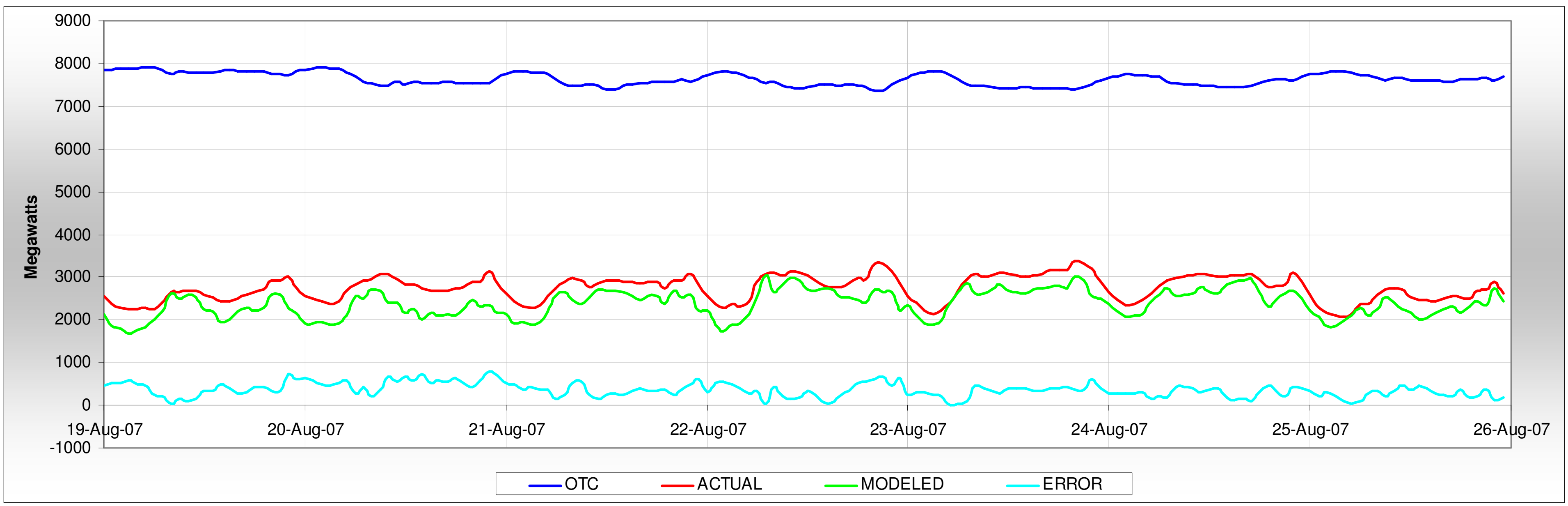
5.5.1 Cross Cascades North



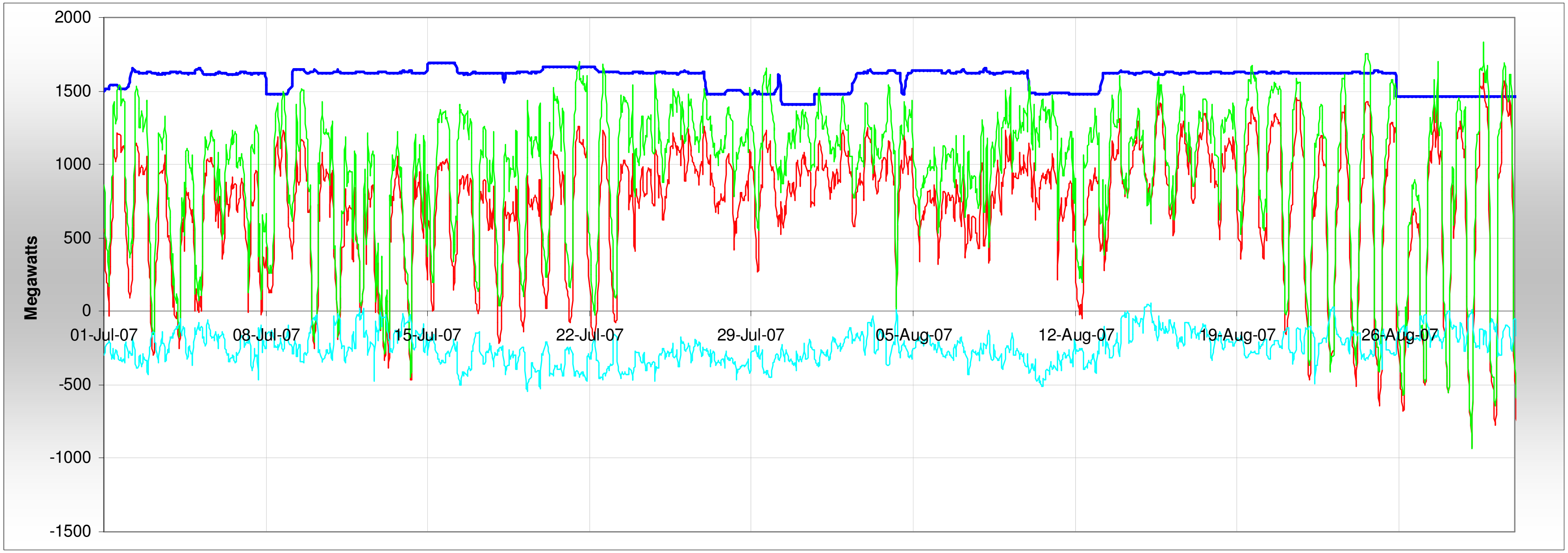


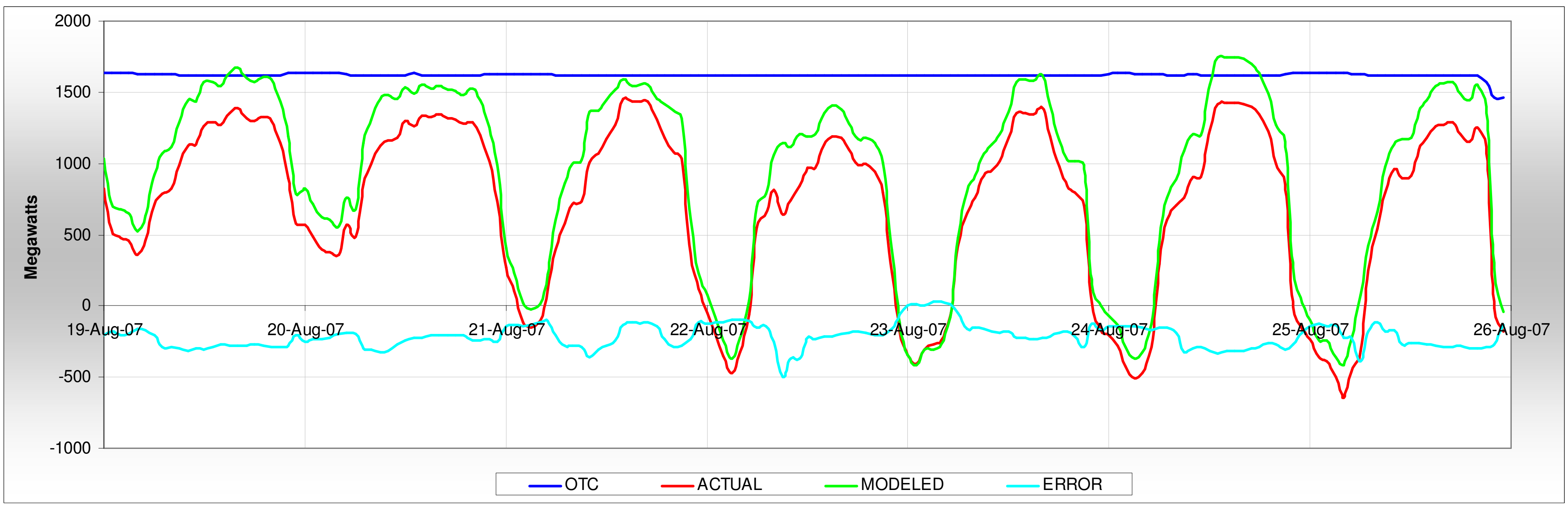
5.5.2 Cross Cascades South



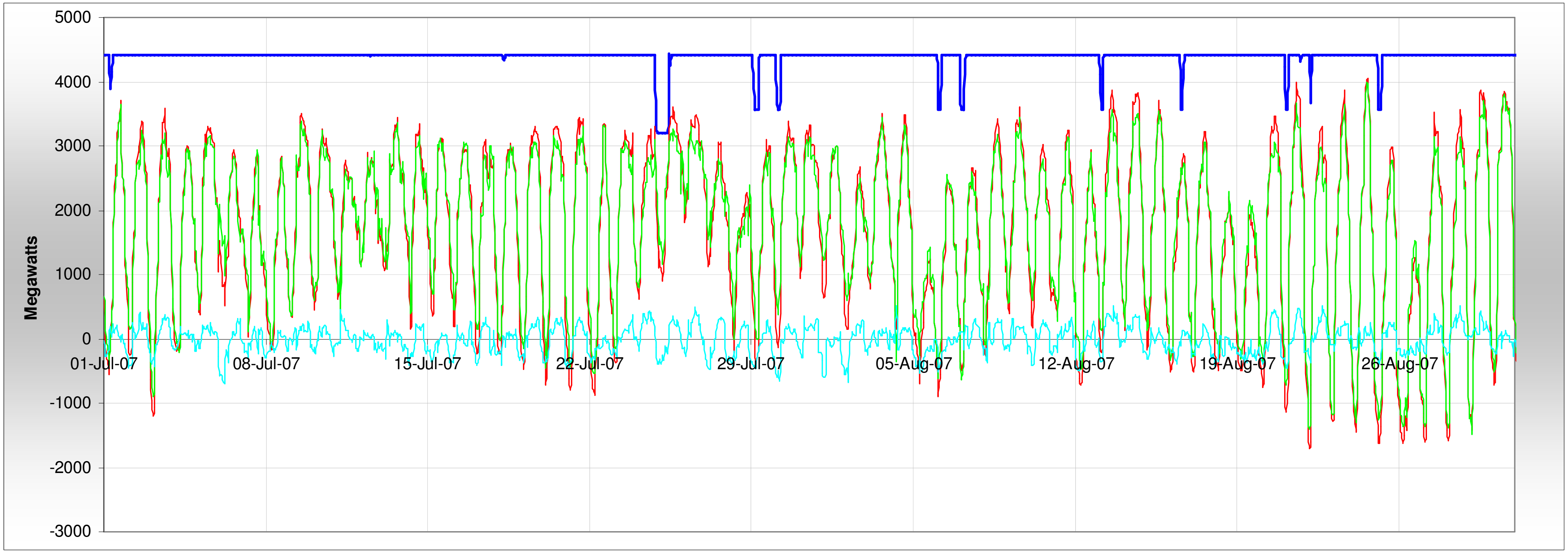


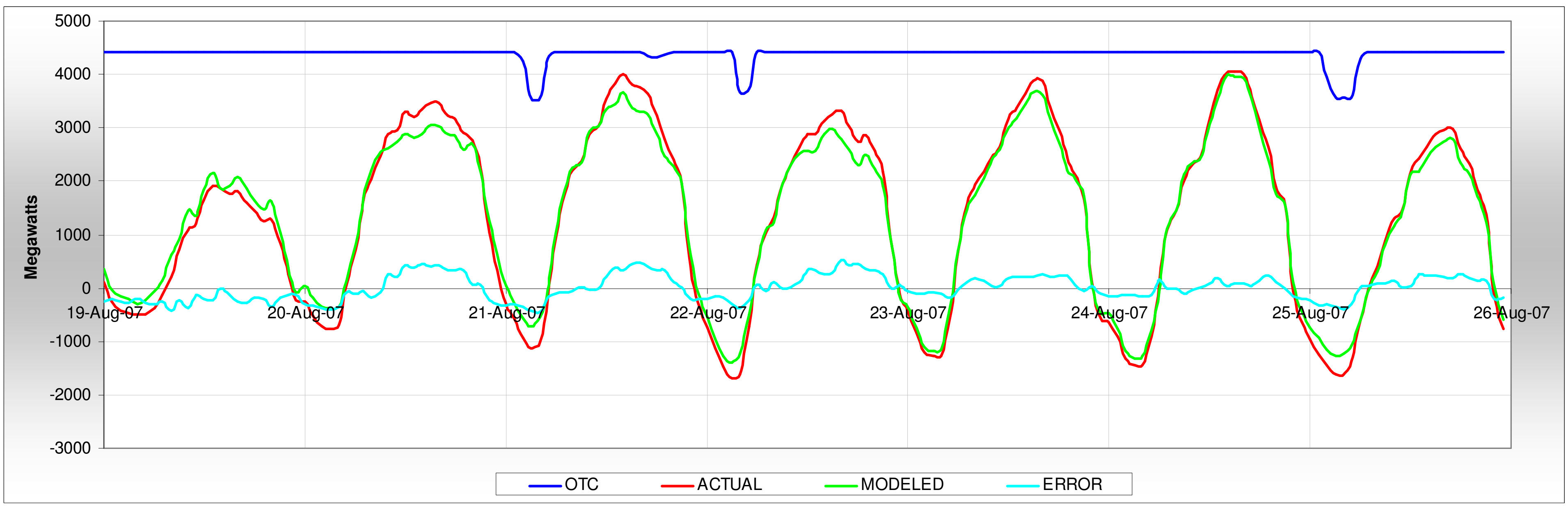
5.5.3 Monroe-Echo Lake



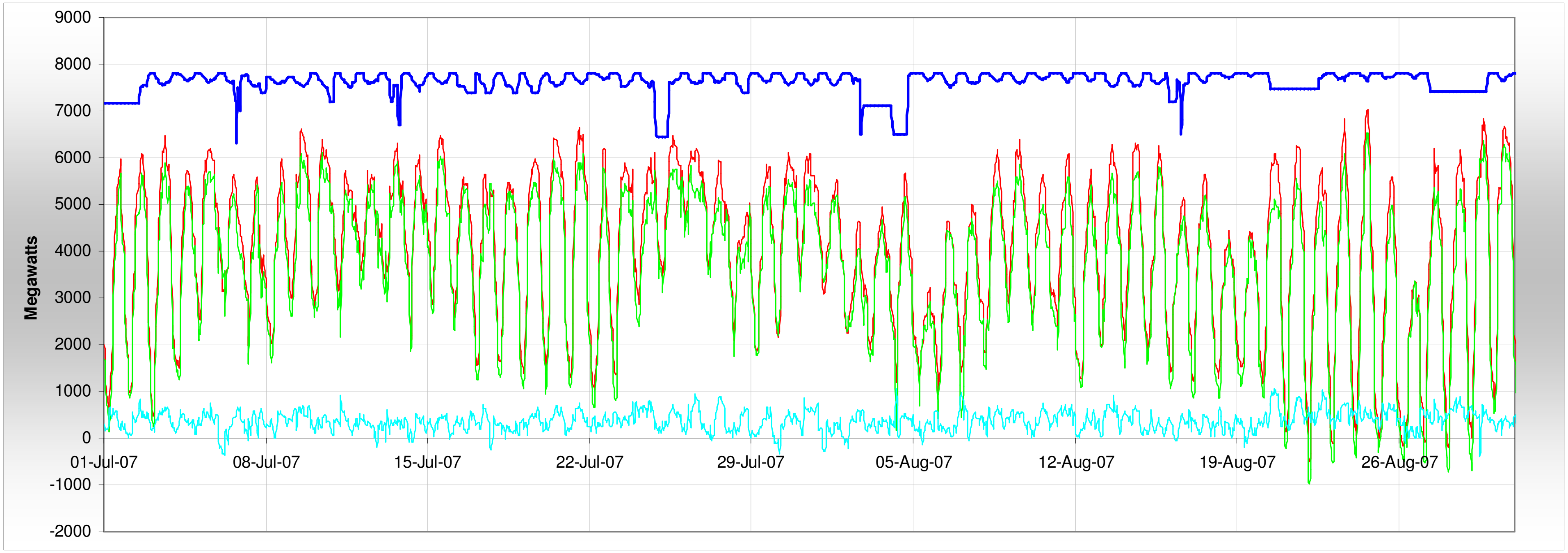


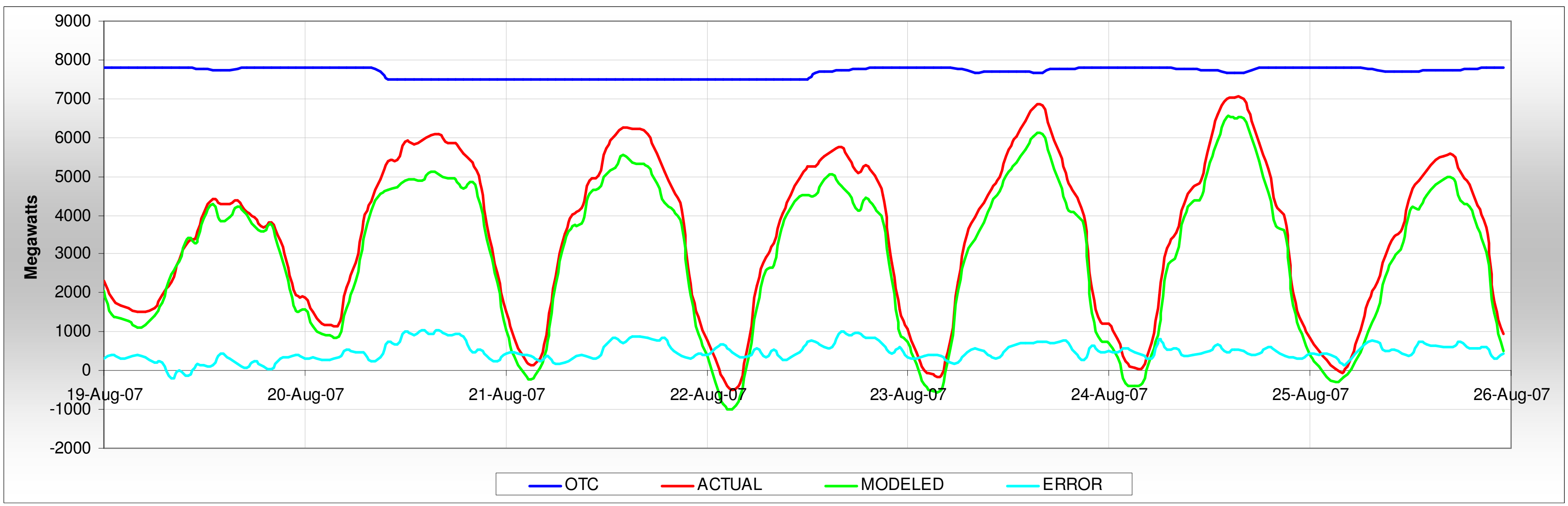
5.5.4 North of Hanford



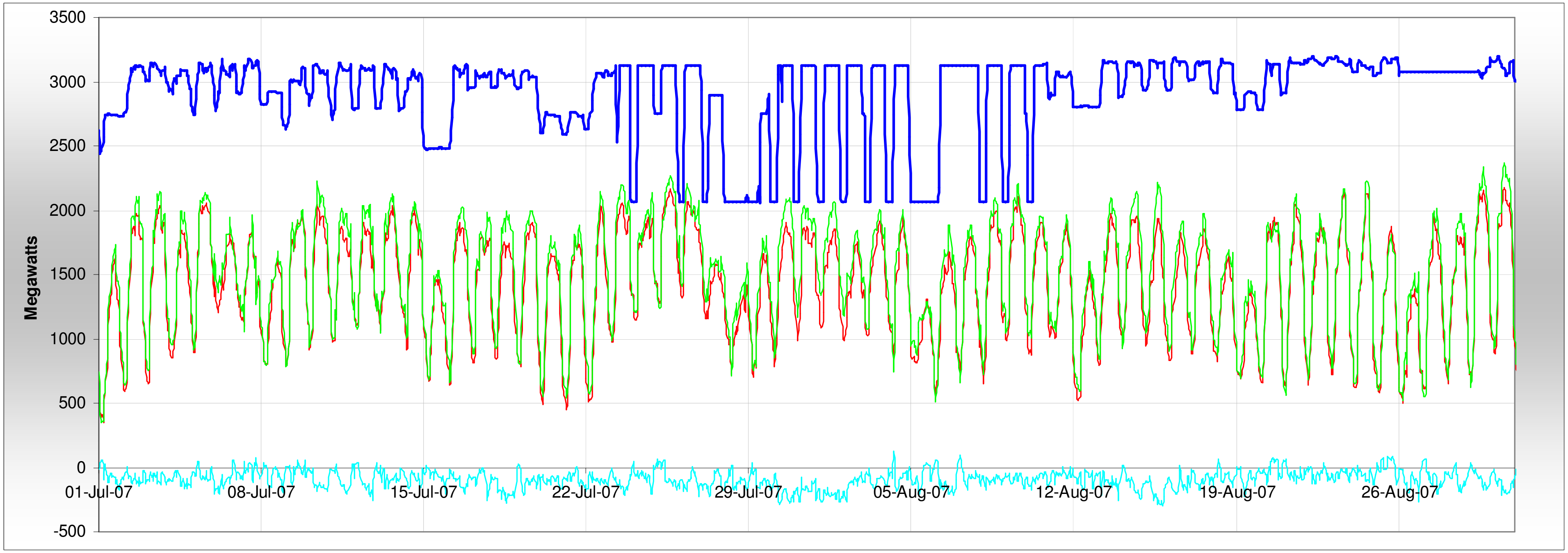


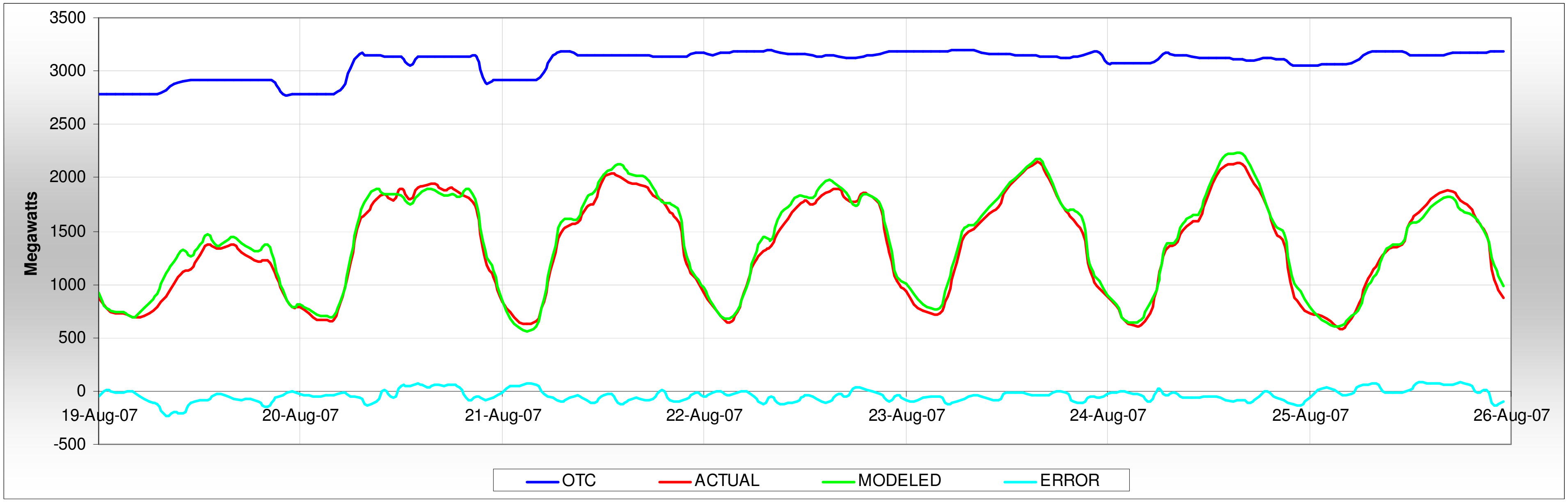
5.5.5 North of John Day



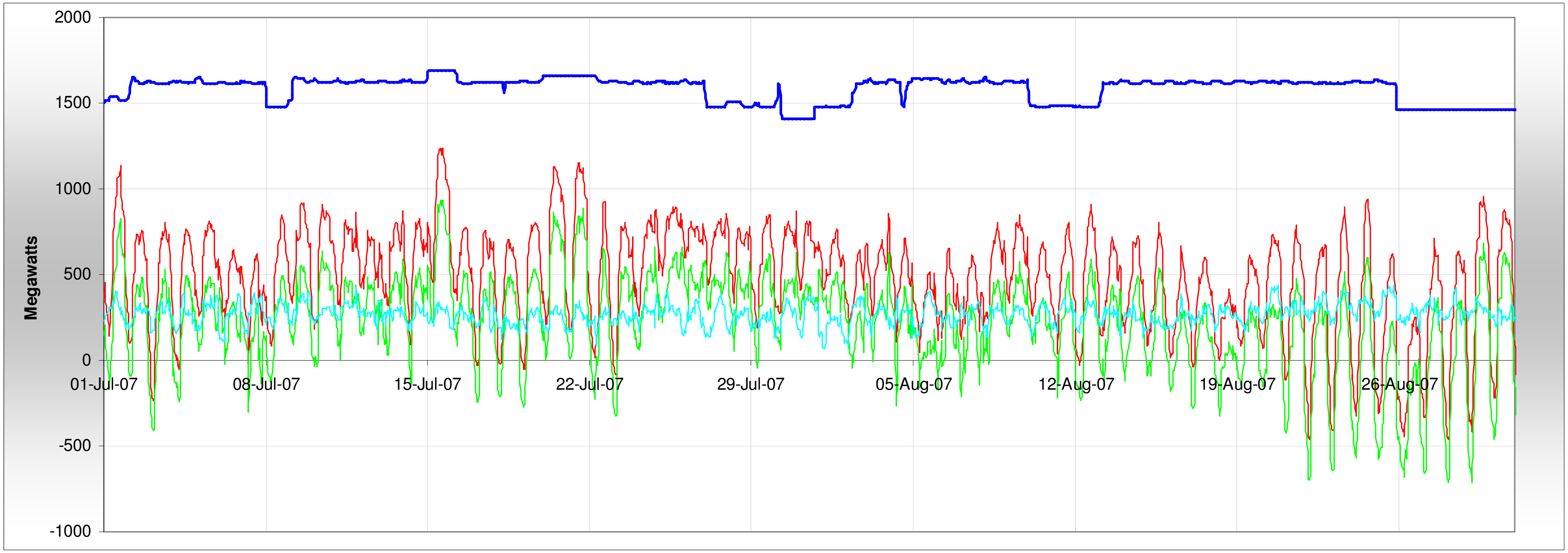


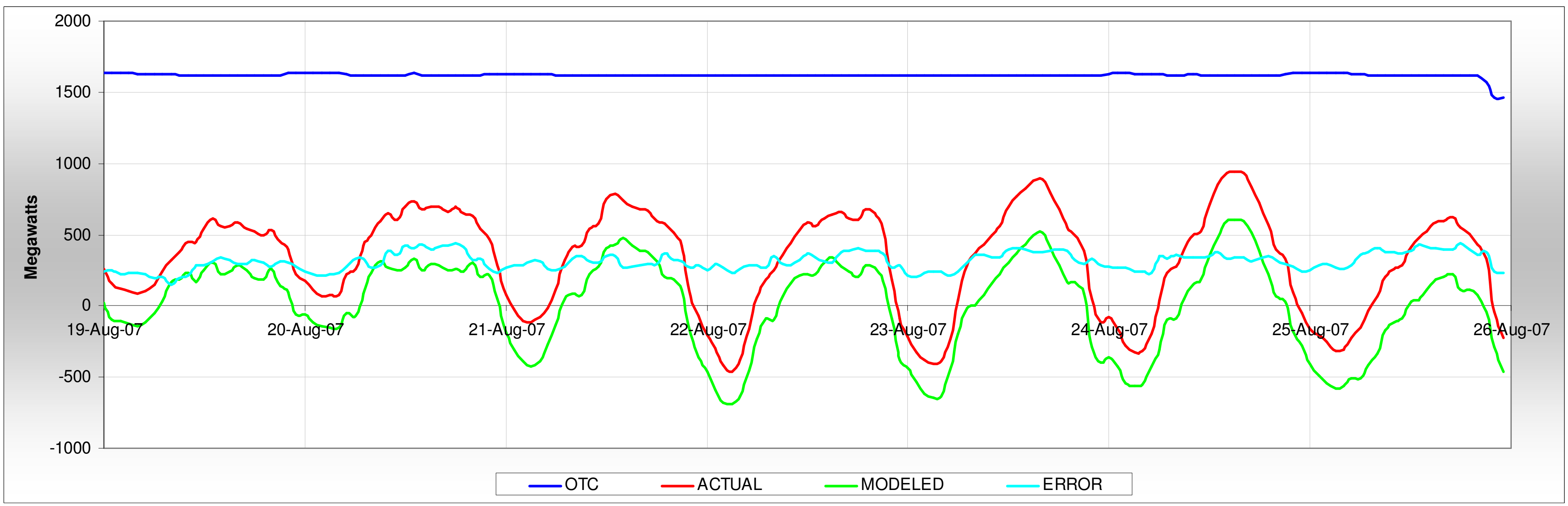
5.5.6 Paul-Allston



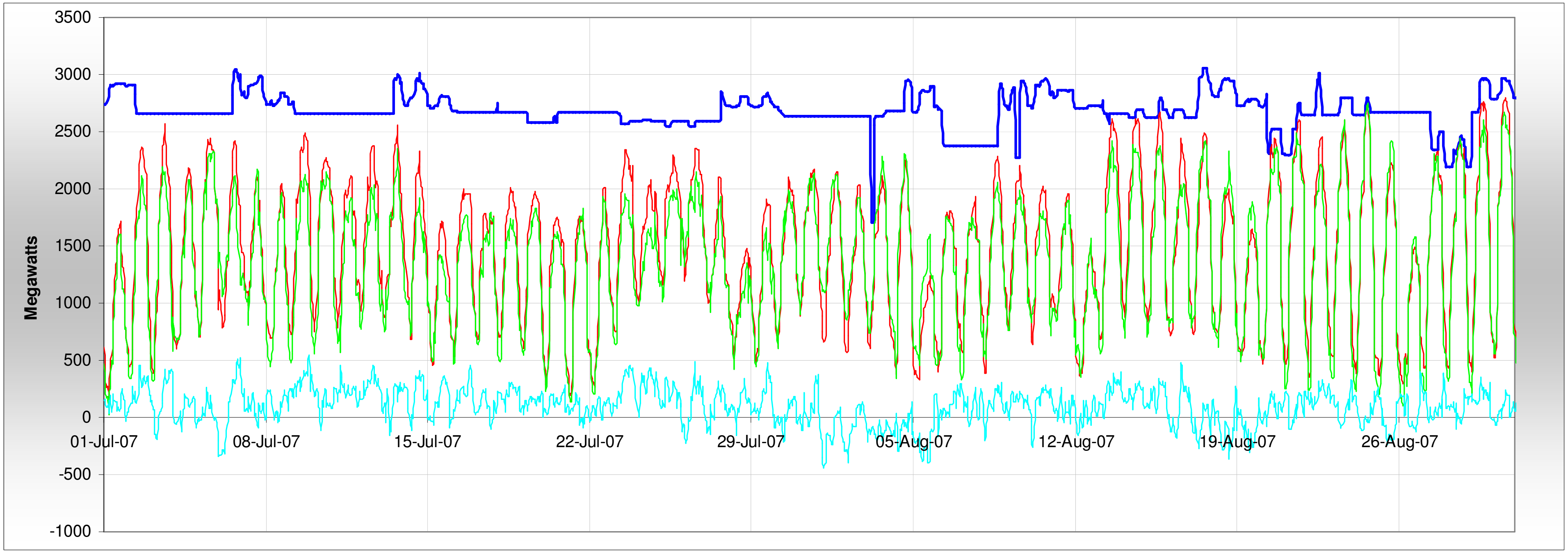


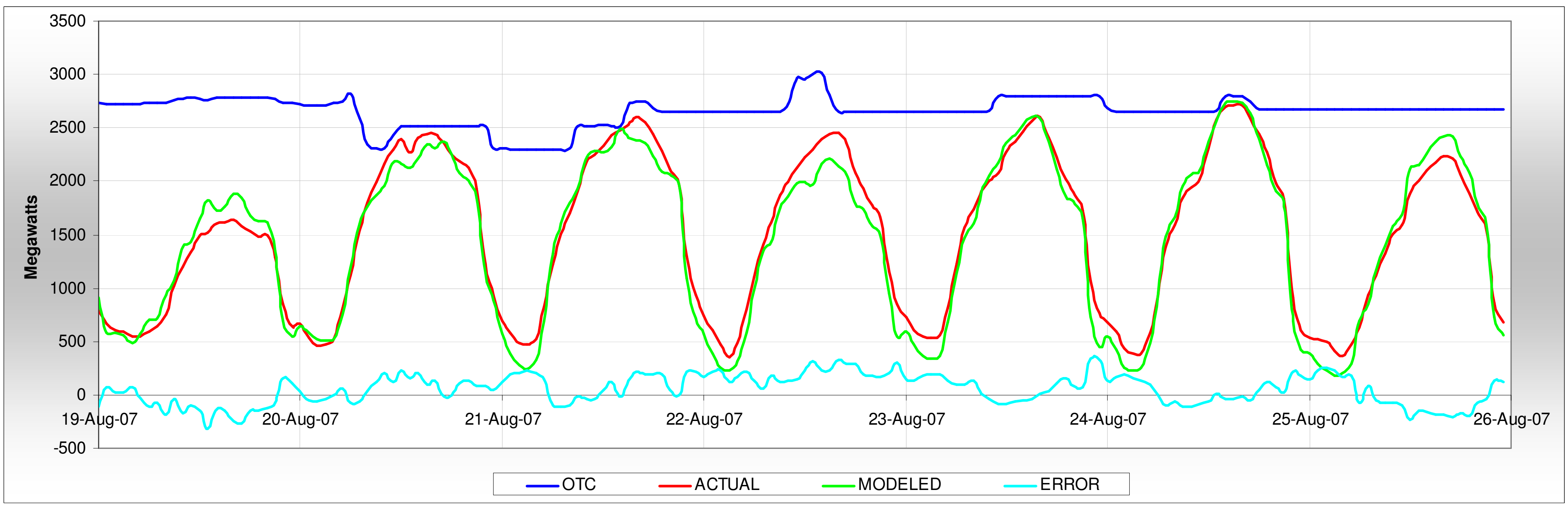
5.5.7 Raver-Paul



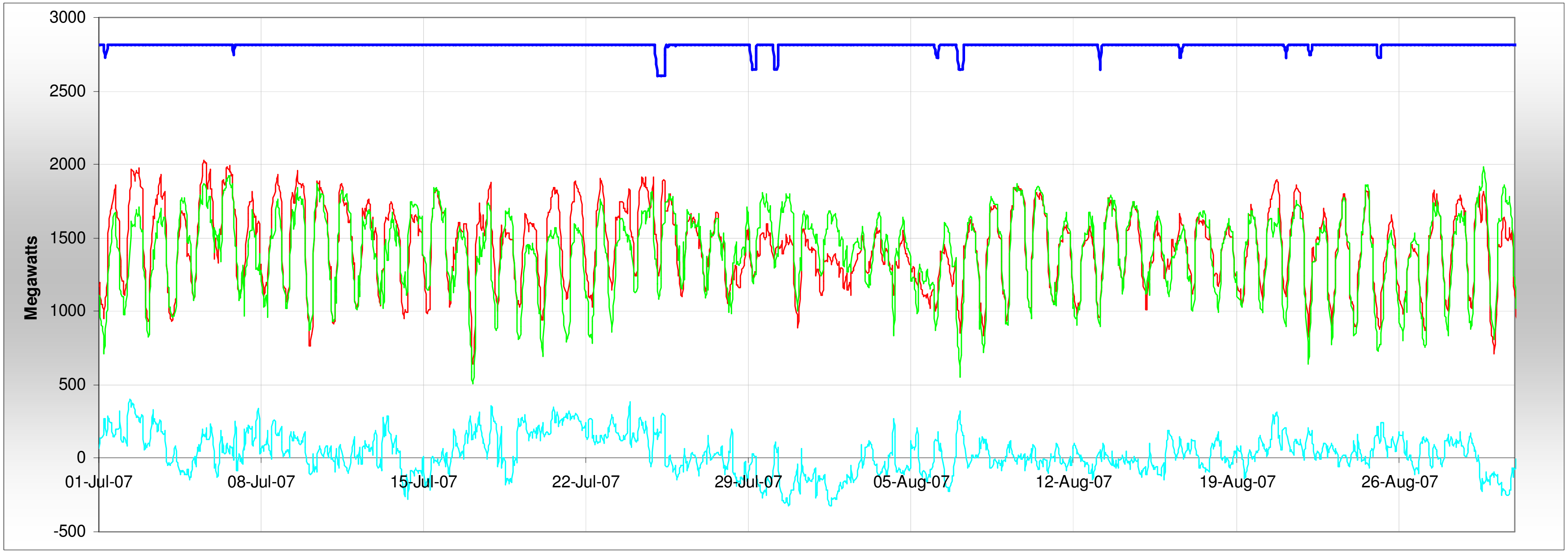


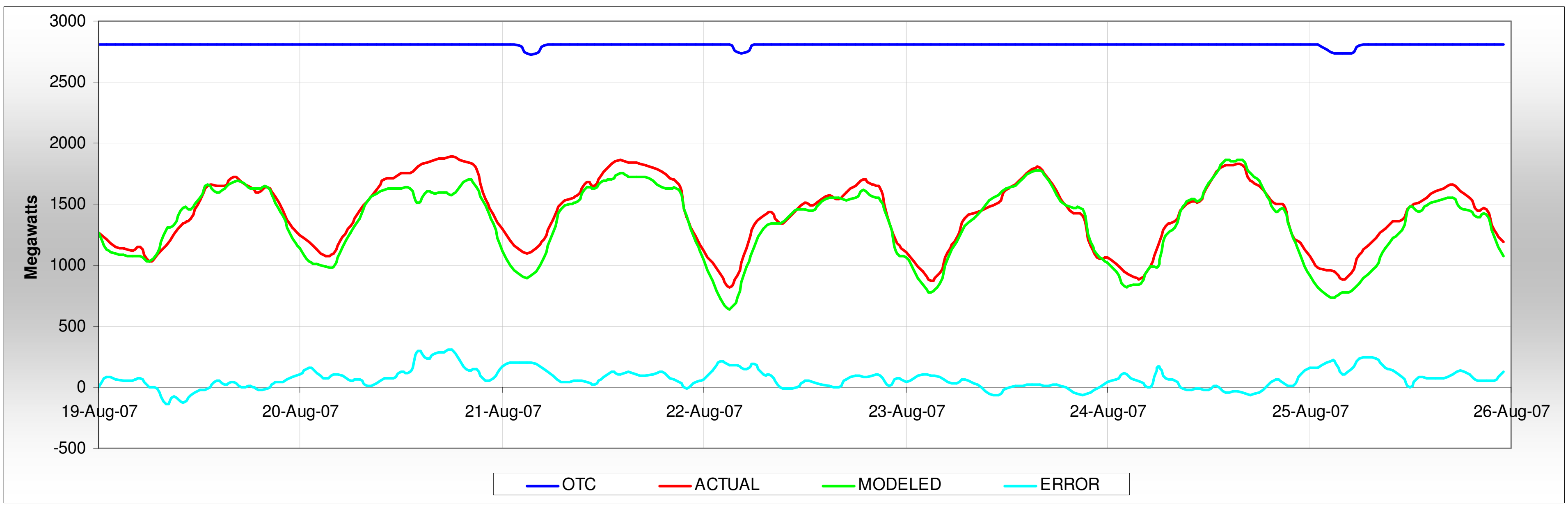
5.5.8 South of Allston



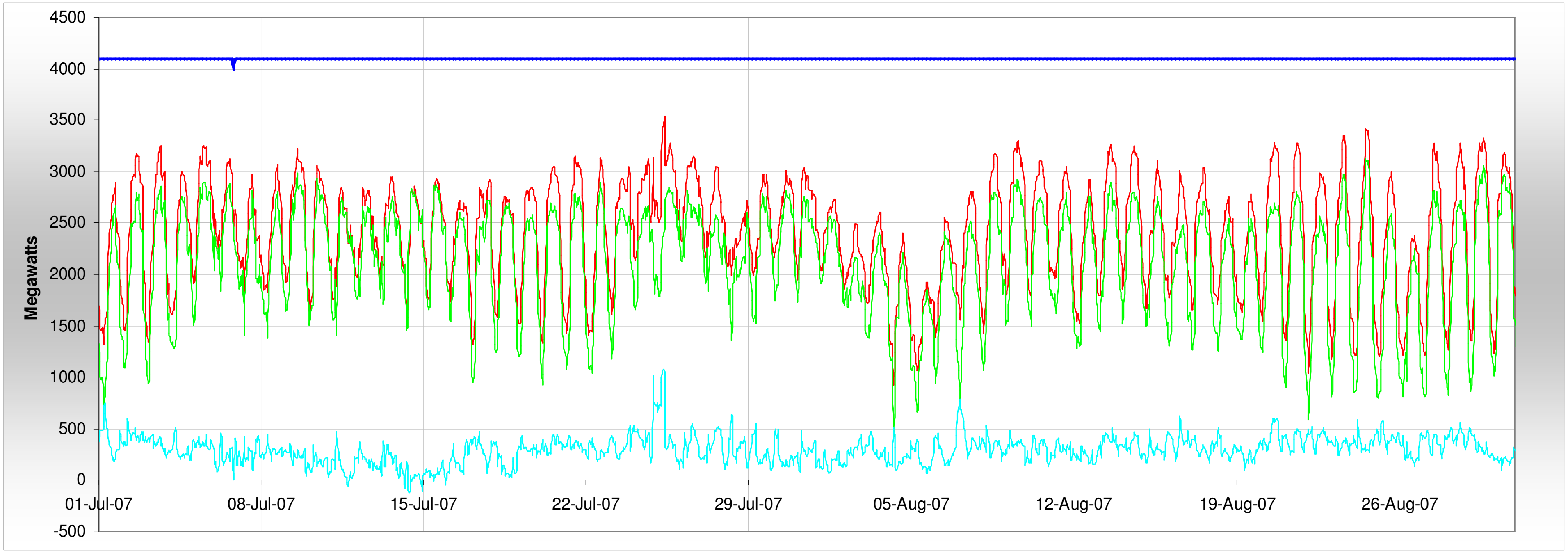


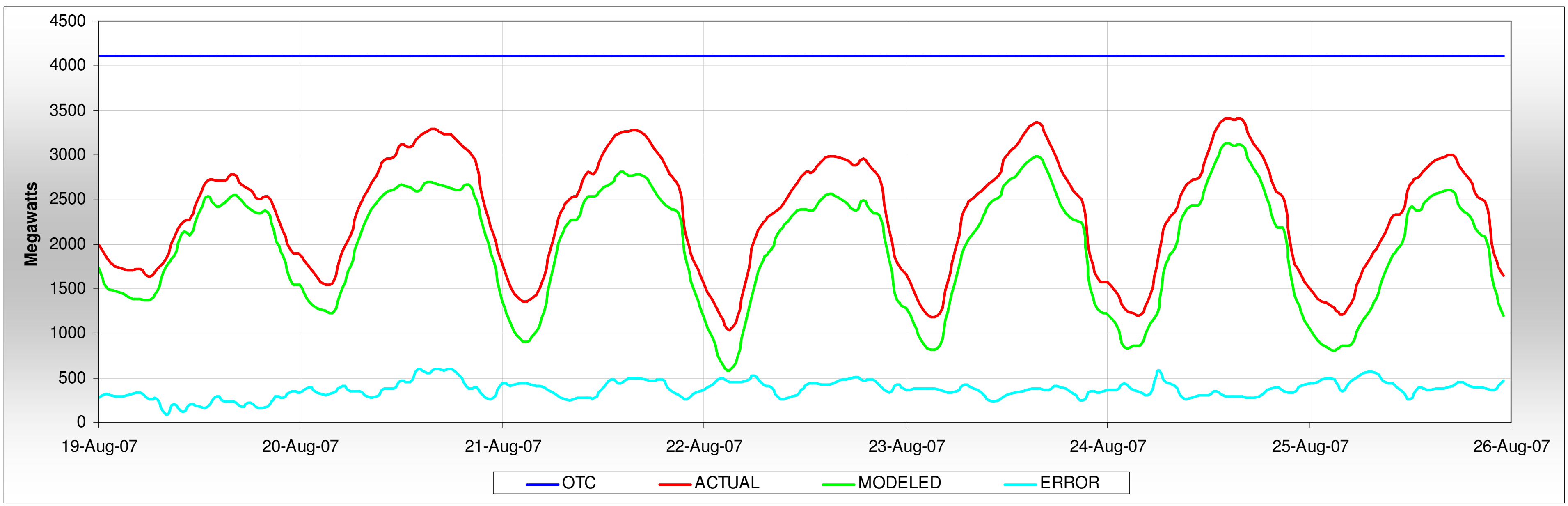
5.5.9 West of McNary





5.5.10 West of Slatt





5.6 Forecasted Network Flow Result Statistics

5.6.1 Cross Cascades North (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.991	0.976	0.962
MEAN ERROR	0.3	2.4	4.5
STDEV of ERROR	112.9	181.5	226.4
MEAN ABS ERROR	81.6	127.3	159.2
STDEV of ABS ERROR	78.0	129.3	160.9
% RELATIVE ERROR (ACTUAL)	2.43%	3.79%	4.74%
% RELATIVE ERROR (OTC)	0.77%	1.20%	1.50%
MEAN ACTUAL			3362.0
MEAN OTC			10624.4

5.6.2 Cross Cascades South (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.955	0.882	0.809
MEAN ERROR	0.1	2.0	3.7
STDEV of ERROR	103.2	168.1	213.6
MEAN ABS ERROR	77.2	122.0	155.0
STDEV of ABS ERROR	68.5	115.6	146.9
% RELATIVE ERROR (ACTUAL)	2.70%	4.27%	5.43%
% RELATIVE ERROR (OTC)	1.02%	1.61%	2.04%
MEAN ACTUAL			2855.5
MEAN OTC			7583.6

5.6.3 Monroe-Echo Lake (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.995	0.991	0.988
MEAN ERROR	0.0	0.6	1.0
STDEV of ERROR	42.7	58.7	70.0
MEAN ABS ERROR	28.6	41.8	51.7
STDEV of ABS ERROR	31.7	41.1	47.2
% RELATIVE ERROR (ACTUAL)	3.73%	5.47%	6.75%
% RELATIVE ERROR (OTC)	1.80%	2.64%	3.27%
MEAN ACTUAL			715.0
MEAN OTC			1582.2

5.6.4 North of Hanford (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.996	0.992	0.988
MEAN ERROR	0.3	0.6	0.9
STDEV of ERROR	116.8	168.8	207.2
MEAN ABS ERROR	83.0	124.7	157.7
STDEV of ABS ERROR	82.2	113.8	134.4
% RELATIVE ERROR (ACTUAL)	4.46%	6.71%	8.48%
% RELATIVE ERROR (OTC)	1.90%	2.85%	3.60%
MEAN ACTUAL			1700.3
MEAN OTC			4380.2

5.6.5 North of John Day (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.996	0.992	0.989
MEAN ERROR	0.5	1.7	3.3
STDEV of ERROR	144.9	204.7	243.1
MEAN ABS ERROR	108.3	153.8	184.7
STDEV of ABS ERROR	96.2	135.0	158.1
% RELATIVE ERROR (ACTUAL)	2.68%	3.81%	4.57%
% RELATIVE ERROR (OTC)	1.42%	2.02%	2.43%
MEAN ACTUAL			4036.1
MEAN OTC			7611.4

5.6.6 Paul-Allston (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.995	0.990	0.986
MEAN ERROR	-0.1	0.2	0.5
STDEV of ERROR	42.2	59.1	70.1
MEAN ABS ERROR	31.2	44.1	52.1
STDEV of ABS ERROR	28.4	39.3	46.9
% RELATIVE ERROR (ACTUAL)	2.21%	3.12%	3.69%
% RELATIVE ERROR (OTC)	1.07%	1.51%	1.79%
MEAN ACTUAL			1414.4
MEAN OTC			2912.2

5.6.7 Raver-Paul (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.993	0.985	0.977
MEAN ERROR	-0.1	0.1	0.5
STDEV of ERROR	35.3	52.0	64.0
MEAN ABS ERROR	26.8	39.2	48.6
STDEV of ABS ERROR	23.0	34.1	41.5
% RELATIVE ERROR (ACTUAL)	5.23%	7.68%	9.52%
% RELATIVE ERROR (OTC)	1.69%	2.48%	3.07%
MEAN ACTUAL			484.4
MEAN OTC			1582.2

5.6.8 South of Allston (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.992	0.983	0.974
MEAN ERROR	0.1	0.6	1.3
STDEV of ERROR	76.7	112.4	138.9
MEAN ABS ERROR	57.4	85.0	106.9
STDEV of ABS ERROR	50.9	73.5	88.6
% RELATIVE ERROR (ACTUAL)	3.90%	5.77%	7.26%
% RELATIVE ERROR (OTC)	2.14%	3.17%	3.99%
MEAN ACTUAL			1472.0
MEAN OTC			2681.1

5.6.9 West of McNary (forecasted flow statistics)

Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.983	0.958	0.937
MEAN ERROR	-0.2	0.4	1.2
STDEV of ERROR	50.3	79.0	96.9
MEAN ABS ERROR	35.0	52.5	64.2
STDEV of ABS ERROR	36.2	59.0	72.7
% RELATIVE ERROR (ACTUAL)	2.43%	3.66%	4.47%
% RELATIVE ERROR (OTC)	1.25%	1.87%	2.29%
MEAN ACTUAL			1436.5
MEAN OTC			2805.8

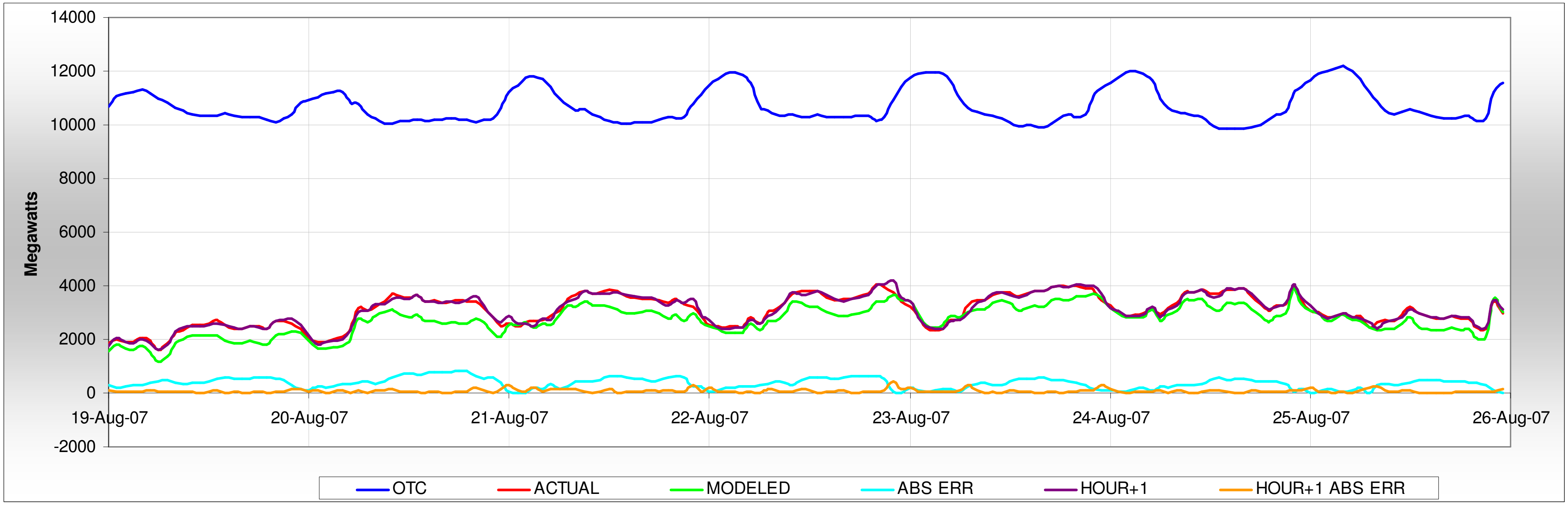
5.6.10 West of Slatt (forecasted flow statistics)

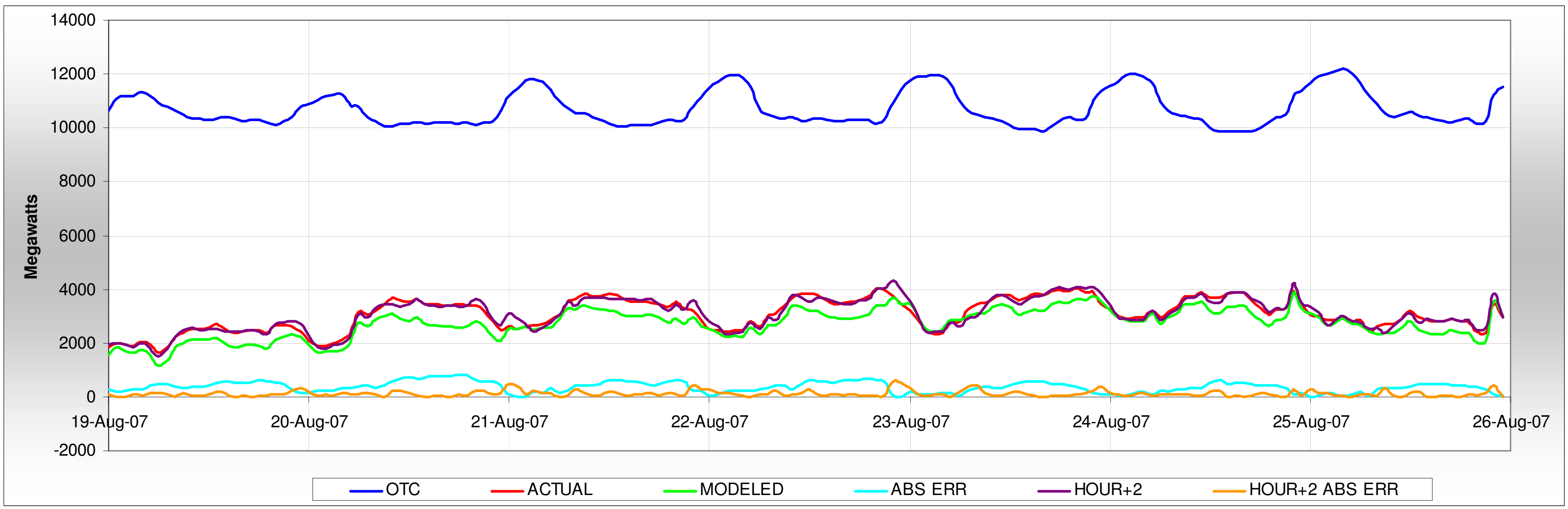
Forecasted Flow	HOUR+1	HOUR+2	HOUR+3
CORRELATION	0.992	0.980	0.970
MEAN ERROR	-0.1	0.9	1.8
STDEV of ERROR	69.1	107.2	131.1
MEAN ABS ERROR	48.0	71.3	87.3
STDEV of ABS ERROR	49.7	80.0	97.8
% RELATIVE ERROR (ACTUAL)	1.99%	2.96%	3.62%
% RELATIVE ERROR (OTC)	1.17%	1.74%	2.13%
MEAN ACTUAL			2408.6
MEAN OTC			4099.9

5.7 Forecasted Network Flow Result Charts

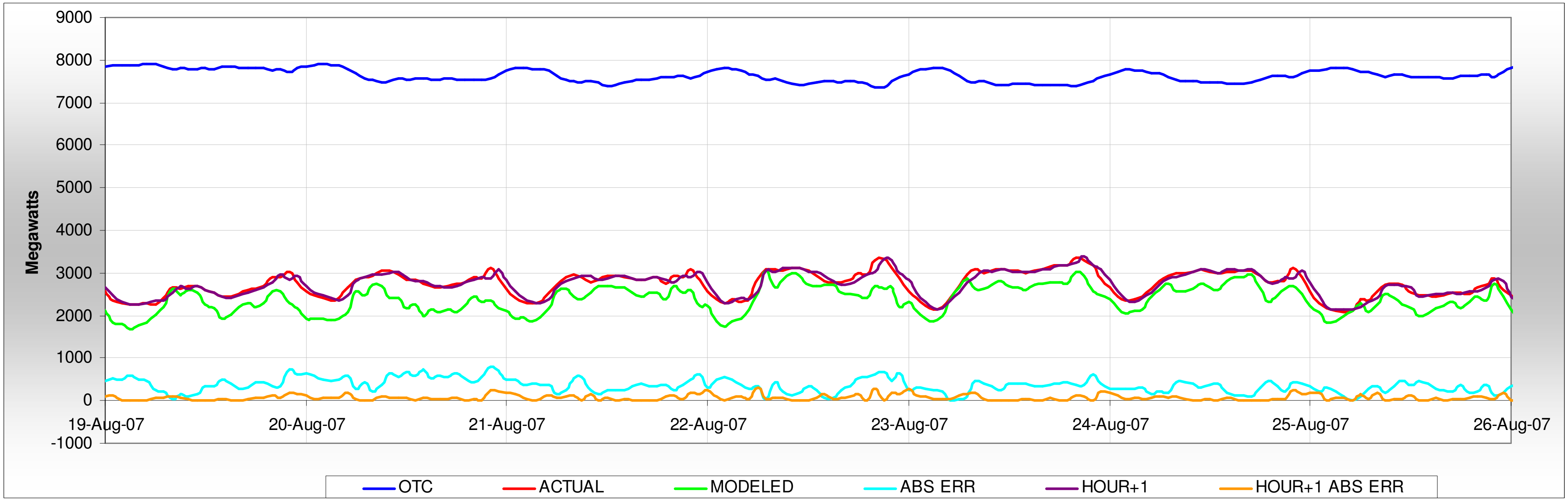
Two charts for the week of August 19th have been provided for each flowgate that visually summarize the performance of the Forecasted Network Flow algorithm: one for hour +1 (t=+1) and other for hour +2 (t=+2).

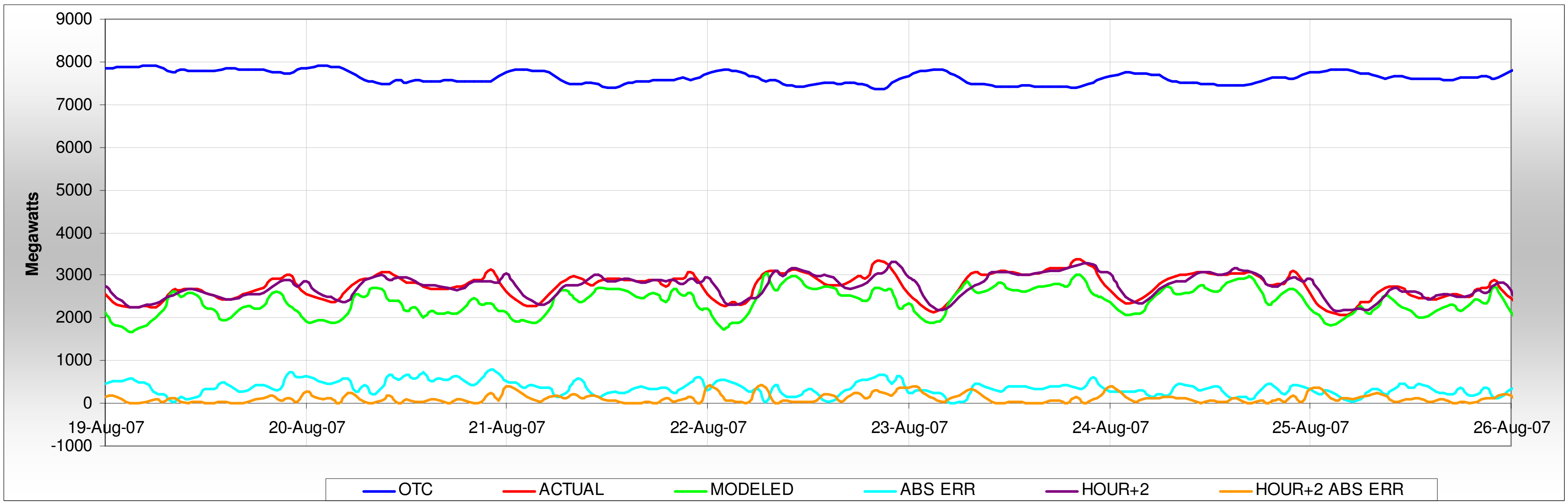
5.7.1 Cross Cascades North



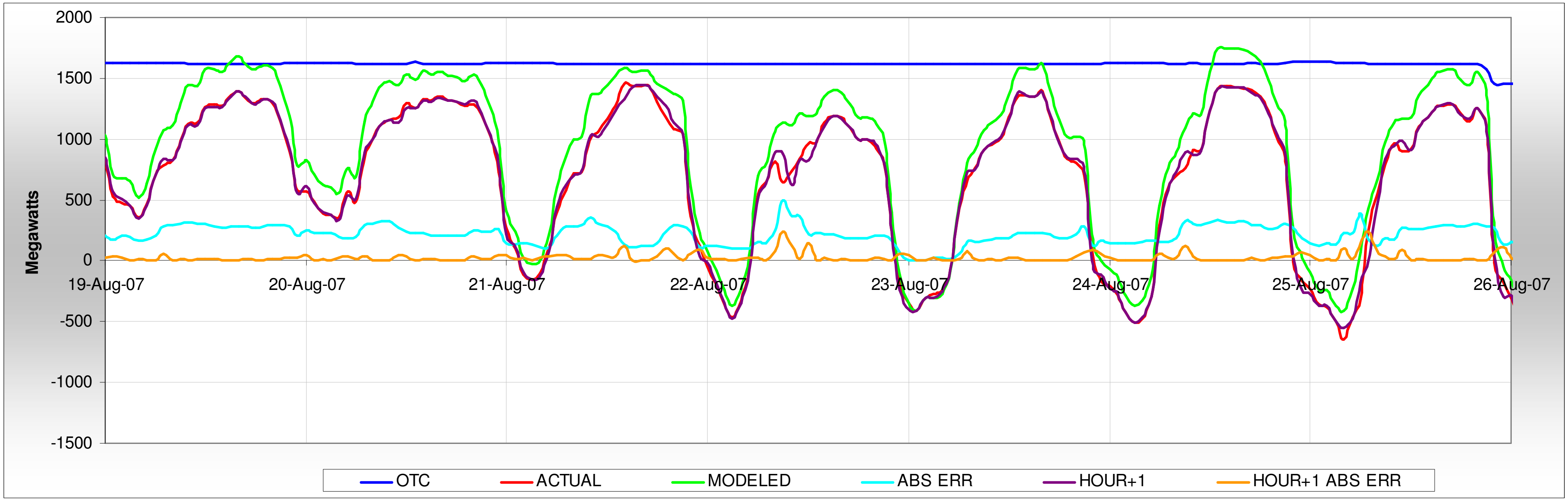


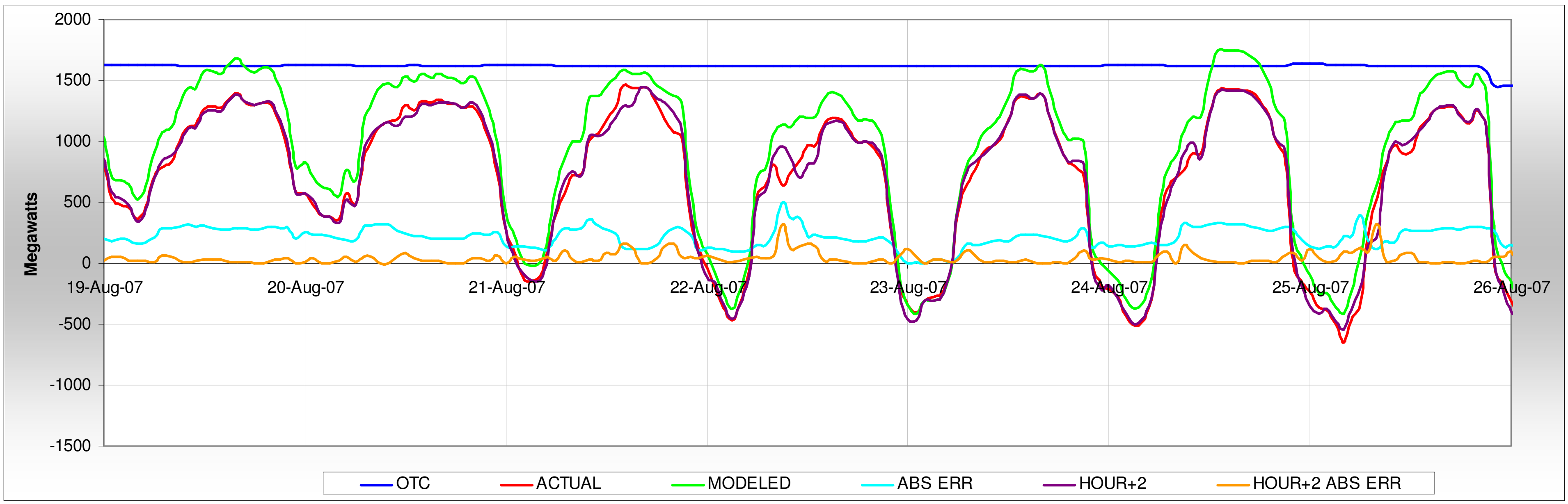
5.7.2 Cross Cascades South



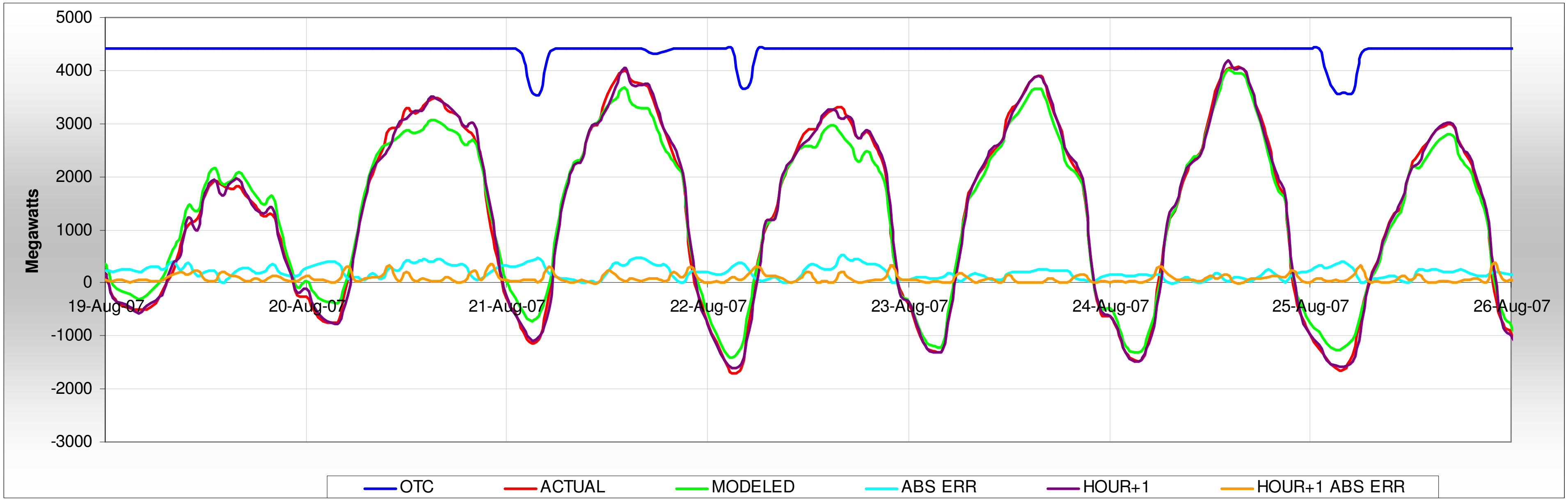


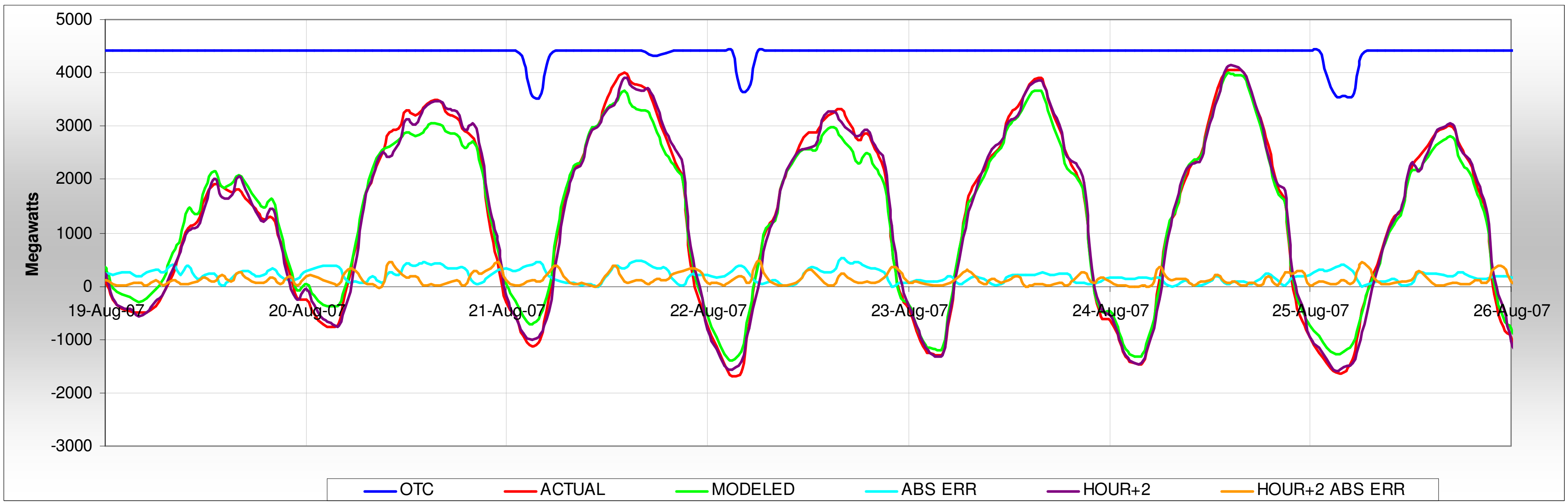
5.7.3 Monroe-Echo Lake



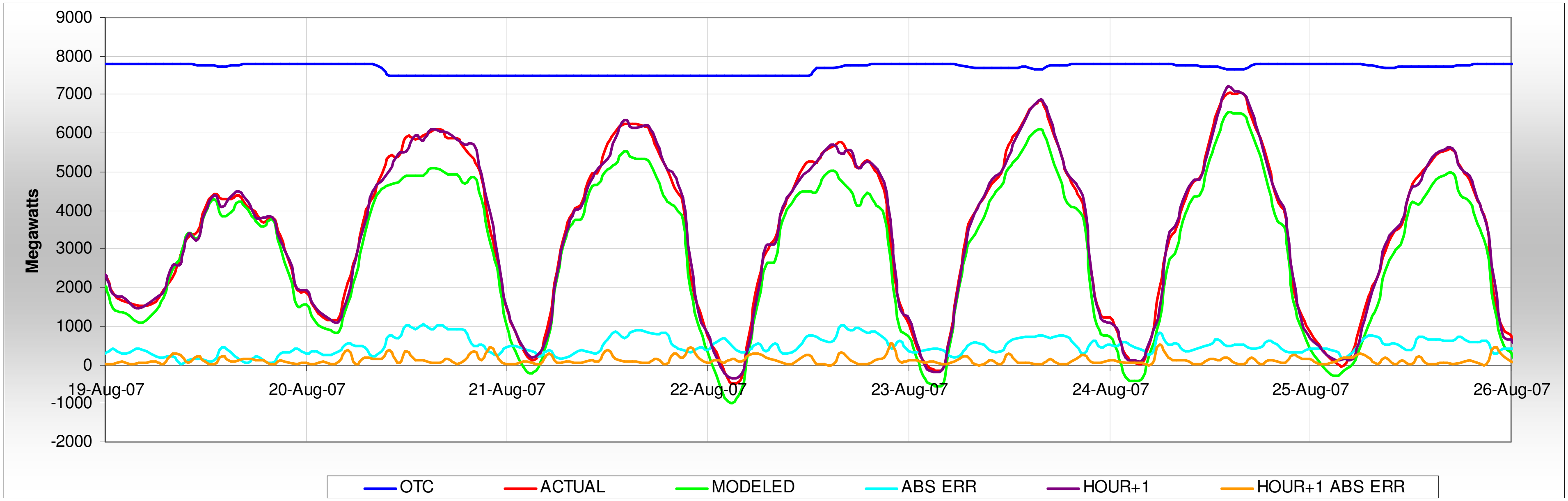


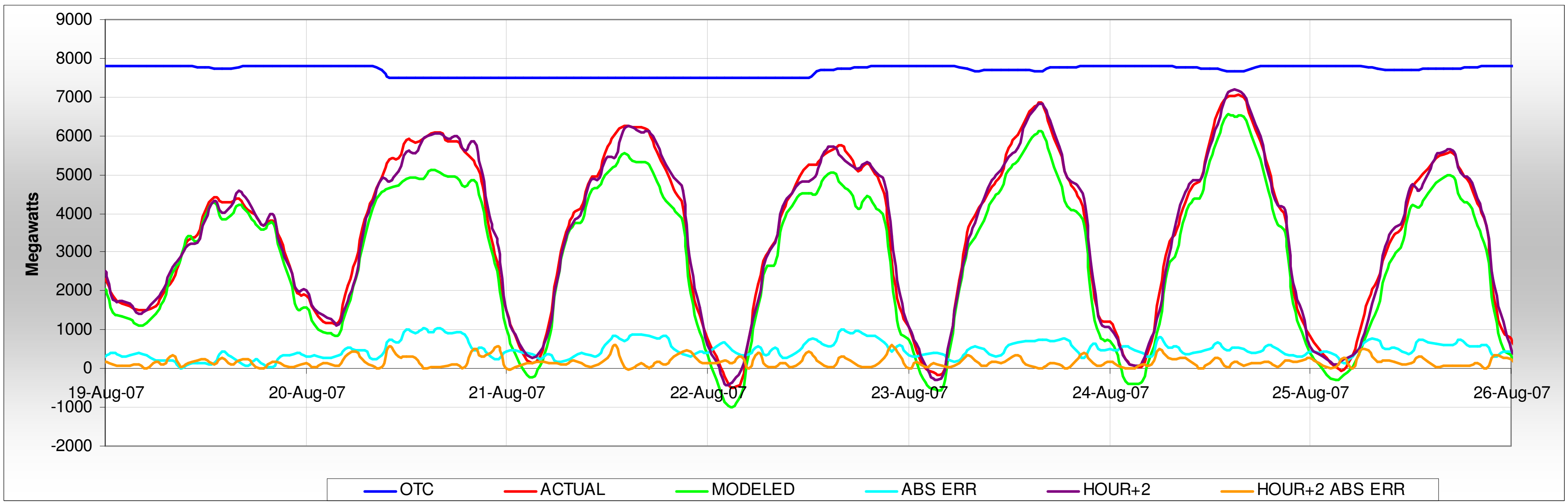
5.7.4 North of Hanford



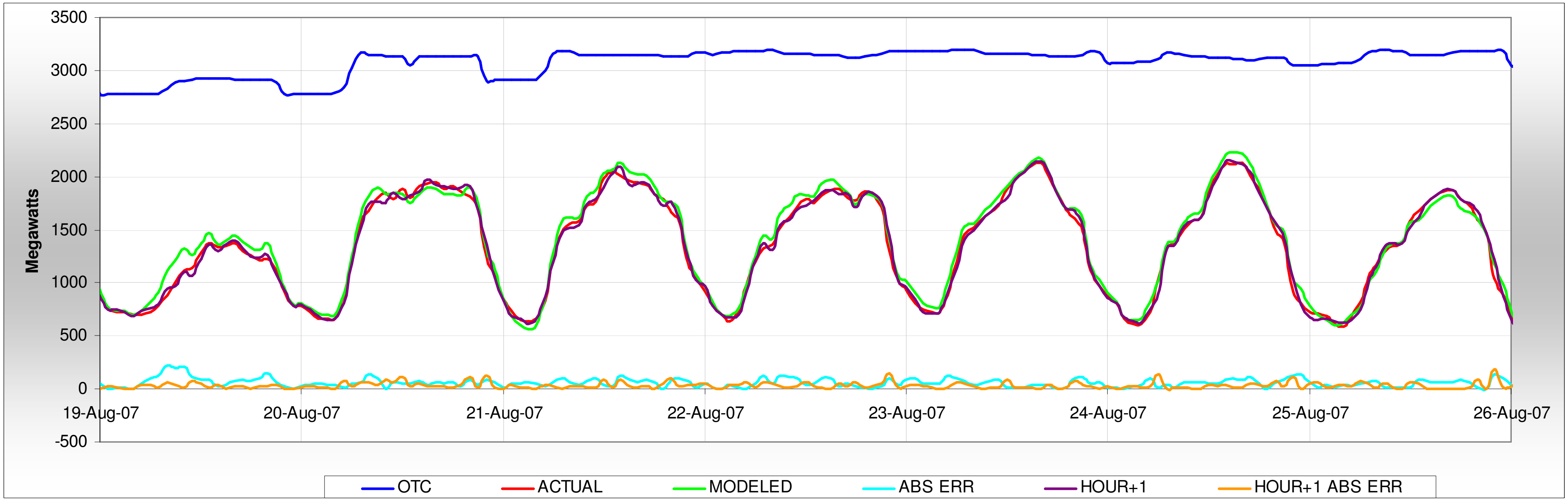


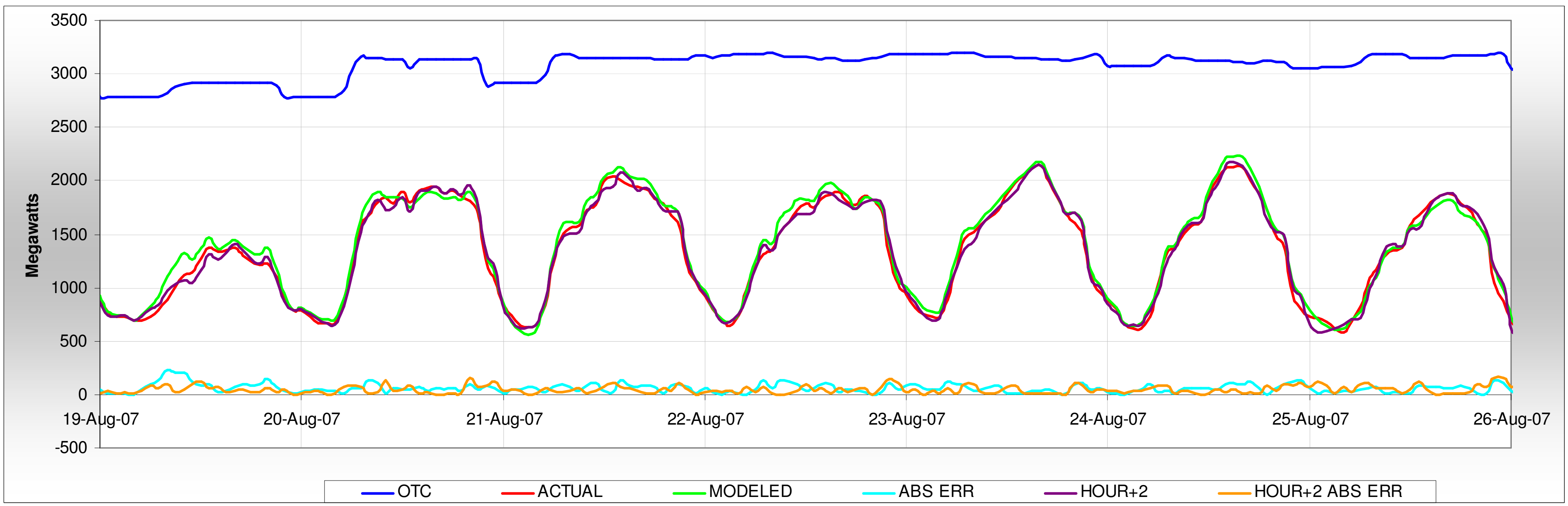
5.7.5 North of John Day



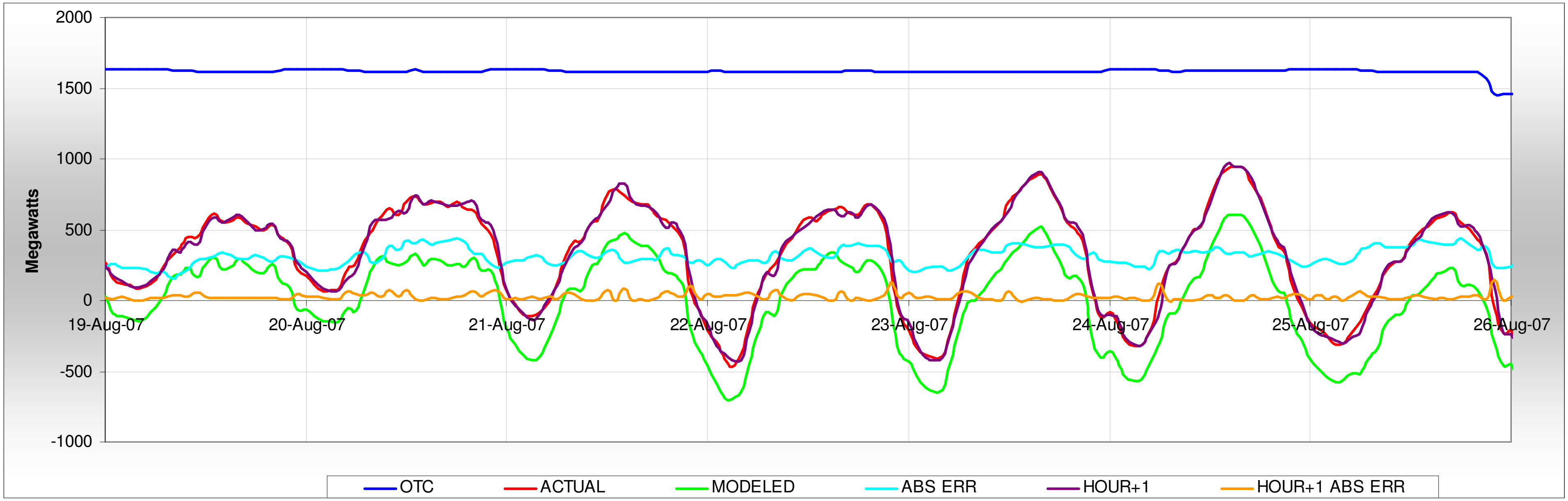


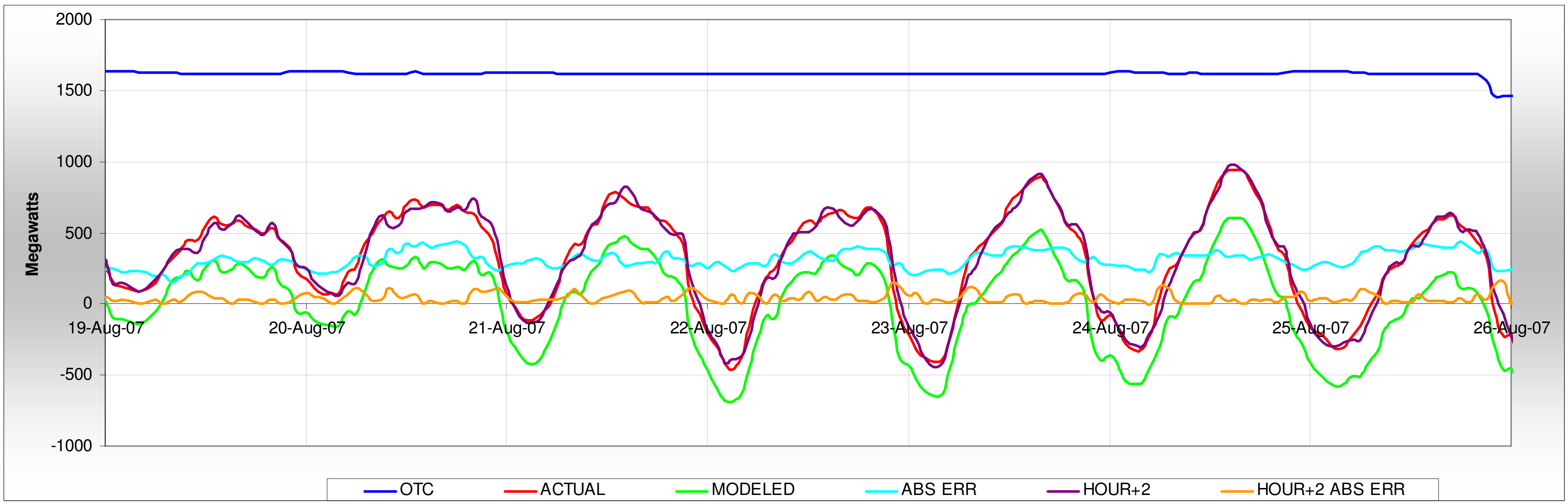
5.7.6 Paul-Allston



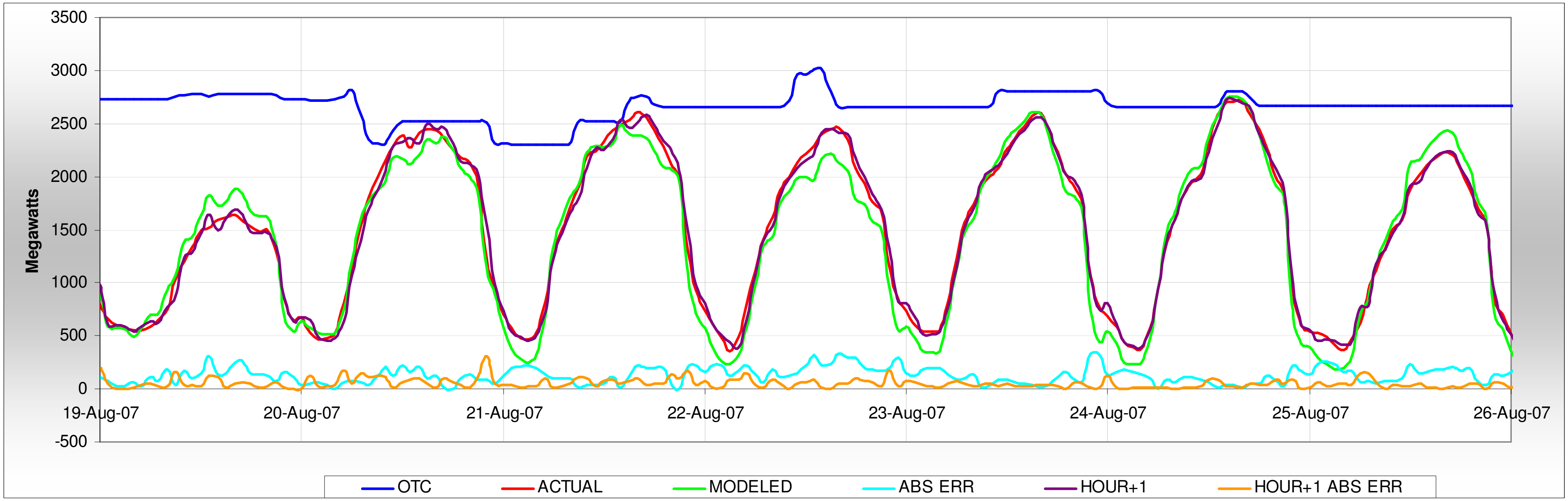


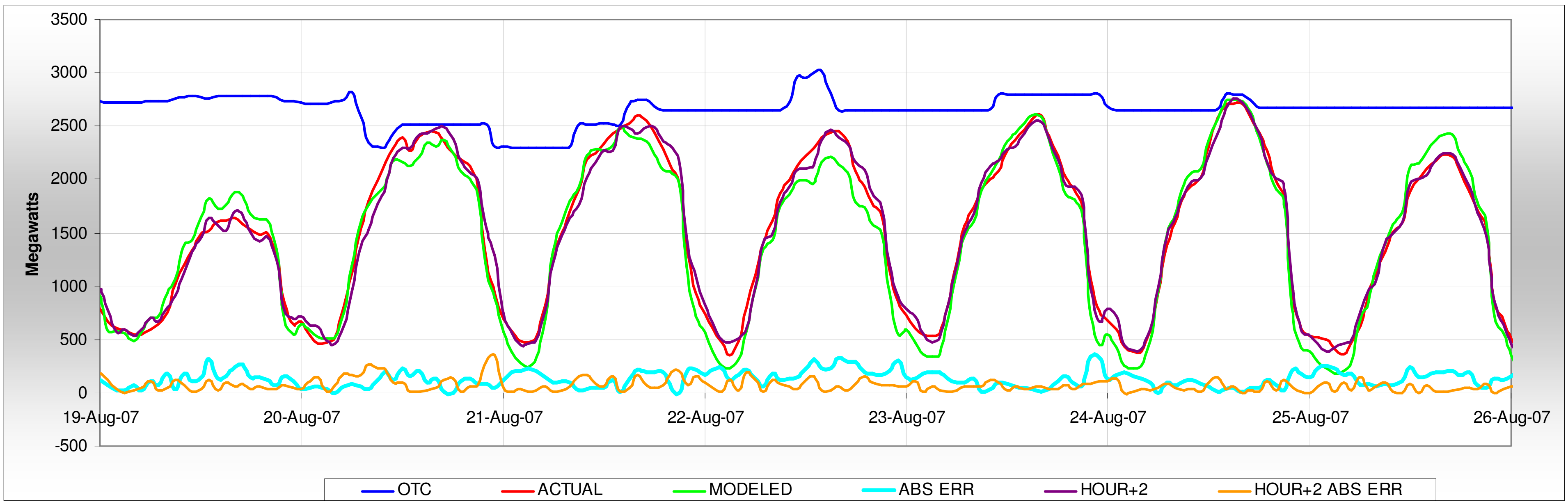
5.7.7 Raver-Paul



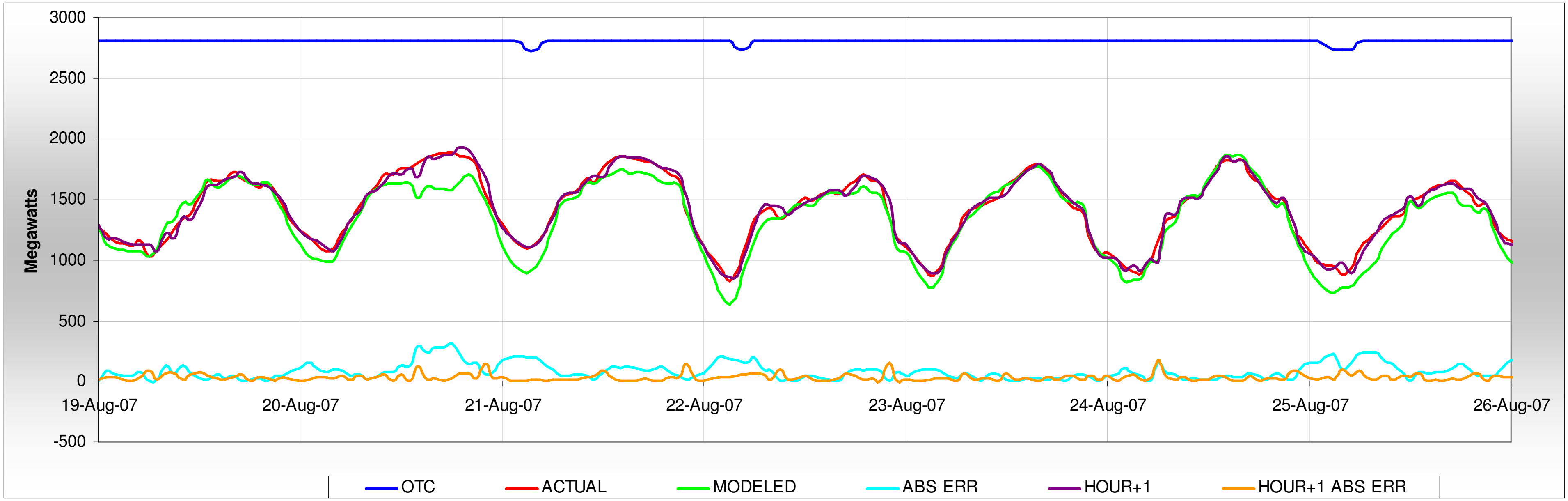


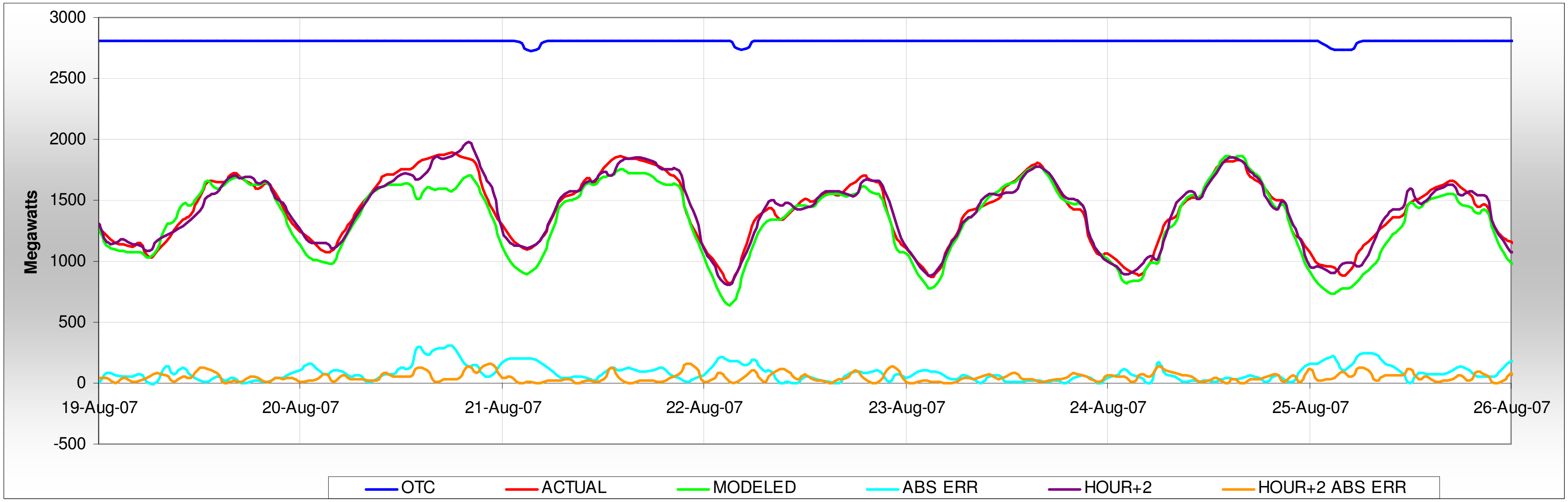
5.7.8 South of Allston



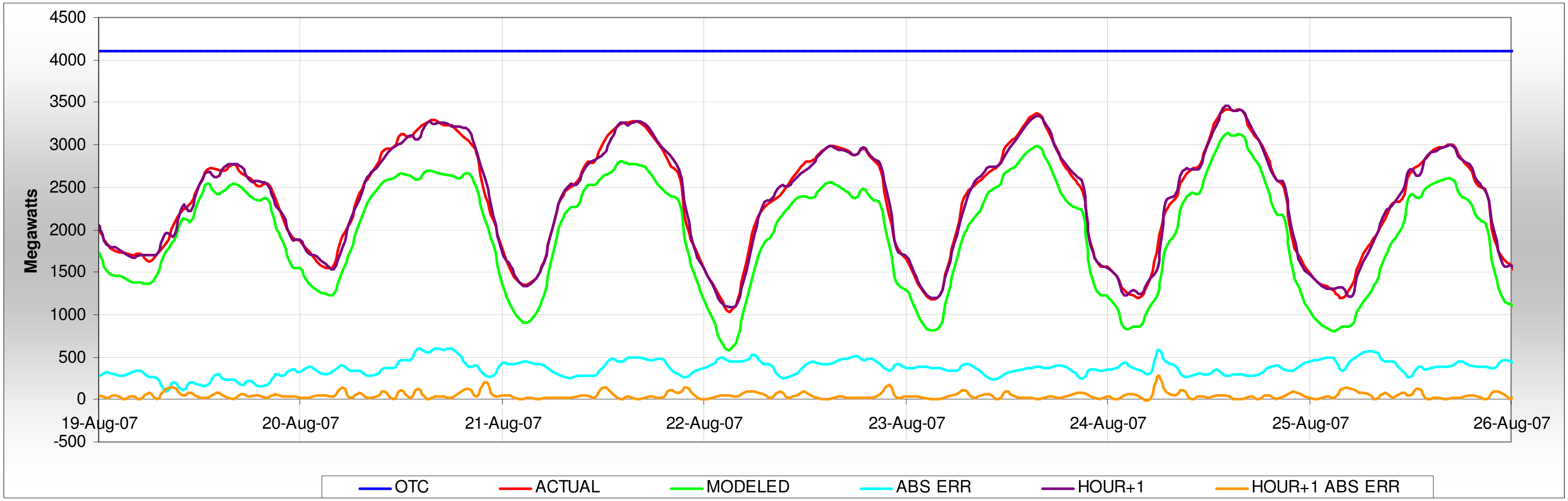


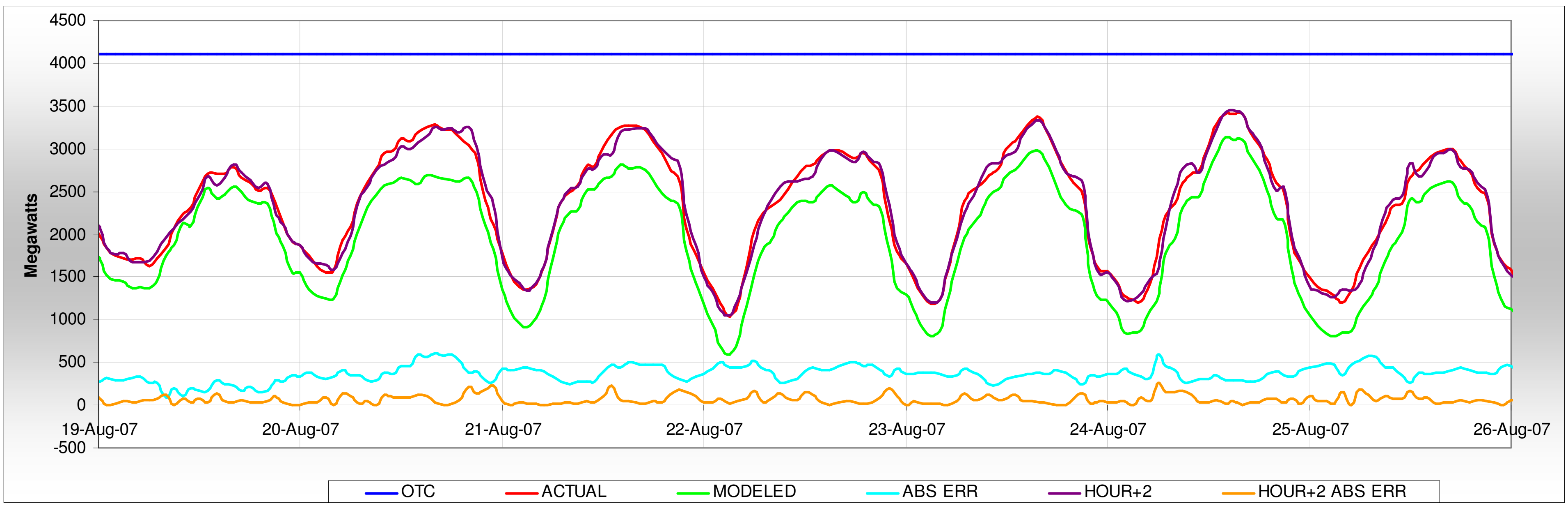
5.7.9 West of McNary





5.7.10 West of Slatt





5.8 Enhanced Modeled Flow using Actual Interchange Data

An enhancement to the basic modeled flow function was experimented with and provided very good results. It involves using the actual interchange values for an adjacent Balancing Authority. Those adjacent Balancing Authorities with numerous interchanges in geographically diverse locations of the network and on different sides of major flowgates produce the best results. The basic algorithm changes as follows:

1. Filter out all tags with the adjacent Balancing Authority as the Upstream Control Area (UPCA) *or* as the Downstream Control Area (DNCA)
2. Of the filtered tags, discard those where the UPCA *and* DNCA are for the same adjacent Balancing Authority
3. With the remaining filtered tags, create pseudo tags by replacing the first BPAT POR or last BPAT POD associated with the adjacent Balancing Authority with a reference bus (such as BPAPower)
4. Create pseudo tags of all of the adjacent Balancing Authorities interchanges relative to the same reference bus as appropriate to the sign of the interchange
5. Integrate the pseudo tags into the Model by:
    a. Filtering out the appropriate $Inadvertent_n$
    b. Filtering out all Tag_n that meet conditions #1 and #2 above
    c. Apply the pseudo tags created in steps #3 and #4

While this method did provide impressive results for some flowgates, more analysis is required. Further, as this method makes heavy use of interchange actual data it would be difficult to integrate it into an operational model without accurate interchange forecasts or a scheduling methodology that provided more resolution at the interchange level. However, sample results have been provided.

5.8.1 Enhanced Modeled Flow Results

Using dataset #3 (see modeled flow results), the enhanced Modeled Flow algorithm was applied to two adjacent Balancing Authorities: Puget Sound Energy (PSEI) and PacifiCorp-West (PACW). The **Monroe-Echo Lake** and **West of Slatt** flowgates were analyzed. The results are summarized below and show an improvement in the performance of the model.

July 1 - August 31 Heavy Load Hours		
Monroe-Echo Lake	**Base**	**Enhanced**
CORREL	0.951	0.976
MEAN ERROR	-267.8	-0.5
STDEV of ERROR	100.1	66.8
MEAN ABS ERROR	268.0	51.2
STDEV of ABS ERROR	99.6	43.0
% RELATIVE ERROR (ACTUAL)	30.68%	5.86%
% RELATIVE ERROR (OTC)	16.96%	3.24%
MEAN ACTUAL		866.7
MEAN OTC		1580.4

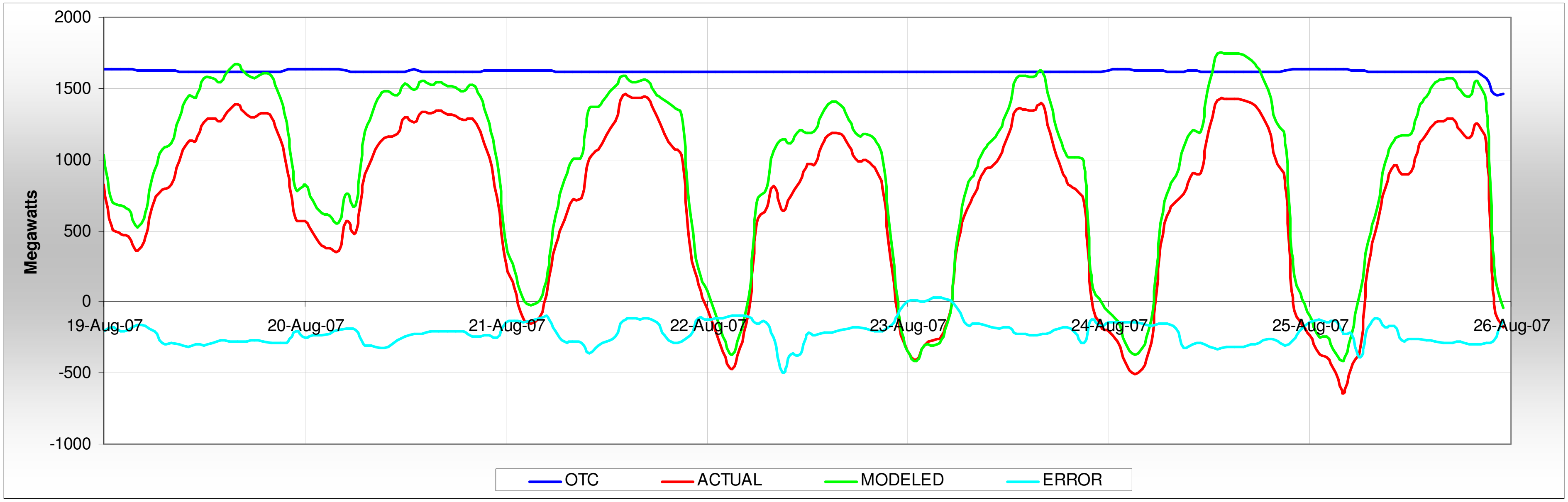
July 1 - August 31 Heavy Load Hours		
West of Slatt	**Base**	**Enhanced**
CORREL	0.947	0.961
MEAN ERROR	297.0	-3.5
STDEV of ERROR	132.0	113.7
MEAN ABS ERROR	298.0	81.7
STDEV of ABS ERROR	129.6	79.0
% RELATIVE ERROR (ACTUAL)	11.21%	3.08%
% RELATIVE ERROR (OTC)	7.27%	1.99%
MEAN ACTUAL		2657.7
MEAN OTC		4099.9

Graphs showing the difference between the original results and those achieved with the enhanced model area included below.

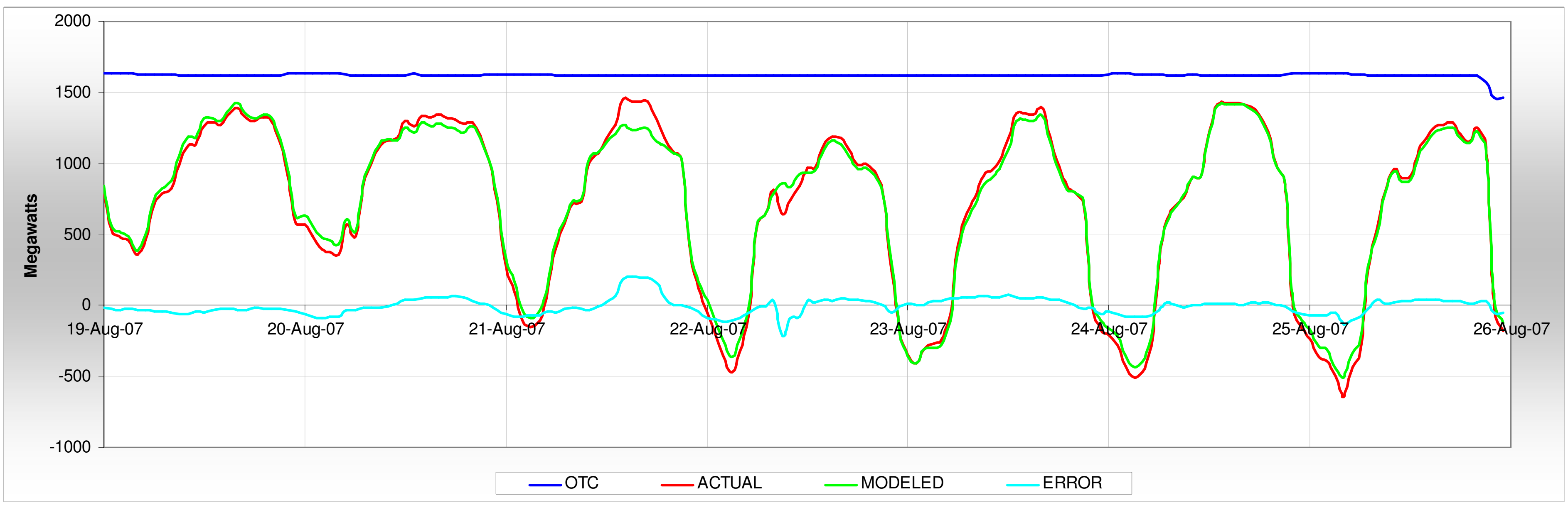
5.8.2 Enhanced Modeled Flow Result Charts

Two charts have been provided for two flowgates, Monroe-Echo Lake and West of Slatt, which visually summarize the performance of the Enhanced Model as compared to the base Model. All charts are for the week of August 19th.

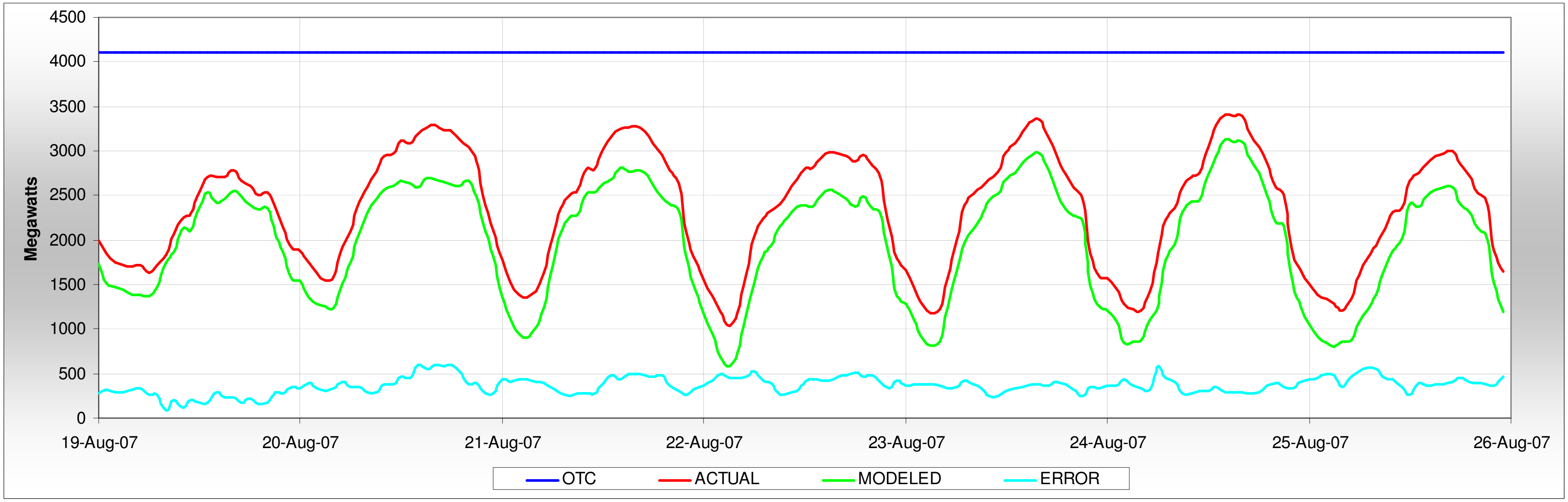
5.8.3 Monroe-Echo Lake (Base Model)



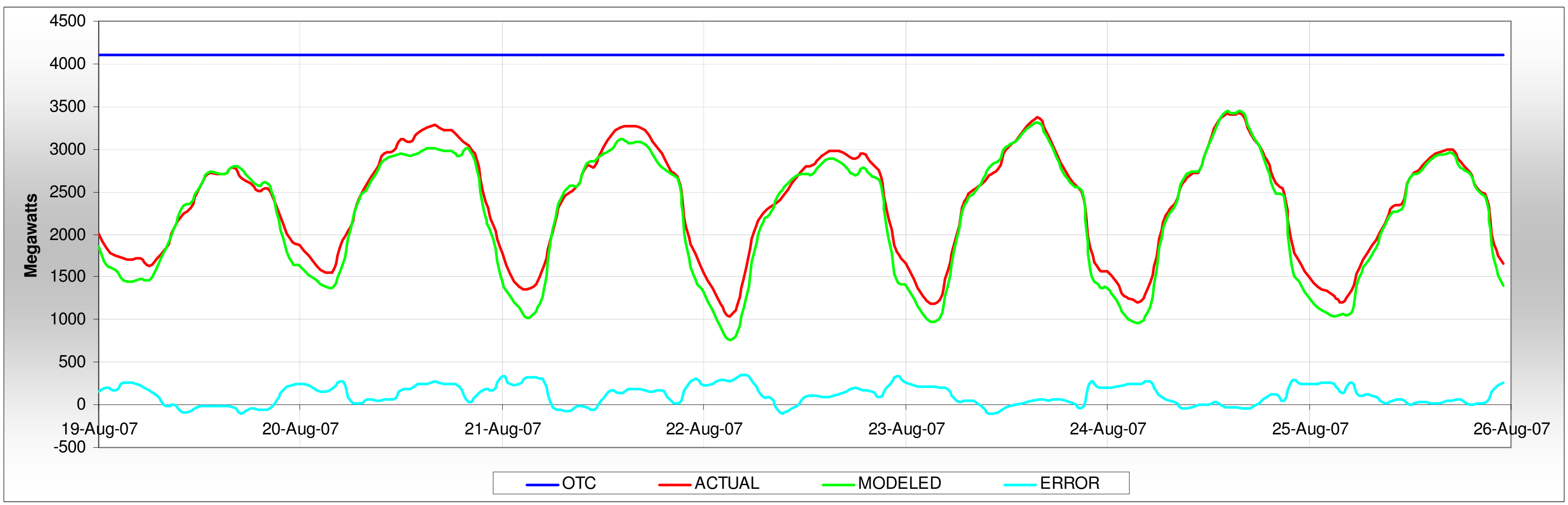
5.8.4 Monroe-Echo Lake (Enhanced Model)



5.8.5 West of Slatt (Base Model)



5.8.6 West of Slatt (Enhanced Model)



5.9 Document History

Date	Version	Change Description	Changed by
8/31/2007	0.1	Initial layout	Todd Kochheiser
9/4/2007	0.2	Drafted all section except results, discussion and conclusions	Todd Kochheiser
97/2007	0.3	Added model results charts	Todd Kochheiser
9/8/2007	0.4	Added statistics	Todd Kochheiser
9/18/07	0.5	Updated statistics and charts	Todd Kochheiser
9/19/2007	0.6	Added Forecasted Flow data	Todd Kochheiser
9/19/2007	0.7	Edited and added content	Todd Kochheiser
9/20/2007	0.8	Added charts for and tables for enhanced model results	Todd Kochheiser
9/20/2007	0.9	Updated based on feedback from CM team	Todd Kochheiser
9/21/2007	0.10	Added net generation chart. Updated forecasting technique section	Todd Kochheiser
9/30/2007	0.11	Updated introduction and fixed some typos	Todd Kochheiser
9/30/2007	0.12	Added summary table of forecasted flows results to t=+2	Todd Kochheiser
9/30/2007	0.13	Added forecasted flow picture for clarification	Todd Kochheiser
10/1/2007	0.14	Refactored layout and moved statistics to appendix.	Todd Kochheiser
10/1/2007	0.15	Small edits based on feedback from Keith Dalia	Todd Kochheiser
10/5/2007	0.16	Edits from Kevin Johnson and Cindy Egleston	Todd Kochheiser
10/6/2007	0.17	Added unscheduled interchange chart	Todd Kochheiser
10/10/2007	0.18	Small edits for presentation	Todd Kochheiser